Decision 05-04-053 April 21, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority to Implement Default CPP Rate Options For Large Customers.	Application 05-01-016 (Filed January 20, 2005)
Application of San Diego Gas & Electric Company (U902-E) for Adoption of a 2005 Default Critical Peak Pricing Structure for Commercial and Industrial Customers with Peak Demands Exceeding 300 kW.	Application 05-01-017 (Filed January 20, 2005)
Southern California Edison Company's (U338-E) Application for Approval of Rate Design Proposals for Large Customers.	Application 05-01-018 (Filed January 20, 2005)

(See Appendix A for List of Appearances)

OPINION ADDRESSING CRITICAL PEAK PRICING RATES FOR CUSTOMERS 200 KILOWATTS AND LARGER

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OPINION ADDRESSING CRITICAL PEAK PRICING RATES FOR CUSTOMERS 200 KILOWATTS AND LARGER

1. Summary

After reviewing the potential demand reduction realistically achievable from implementing the proposed default critical peak tariffs by June 1, 2005 for customers over 200 kilowatts (kW) in demand, the bill impacts (both positive and negative) for customers assuming both no changes in usage and significant changes in usage, and the likelihood that customers would have sufficient information and time to make changes to their loads beginning June 1, 2005, we will not adopt new default rates for Summer 2005. Instead, we lay out information learned from these applications and a process to capture the lessons learned as with the goal of comprehensive rate design reform for 2006. We also make modifications to the current voluntary critical peak pricing tariffs for all three utilities and adopt a new tariff for San Diego Gas & Electric Company (SDG&E) to provide for interruptible capacity in its service territory.

2. Procedural History

The instant applications by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and SDG&E were filed in response to the December 8, 2004 Ruling by Assigned Commissioner Peevey and Administrative Law Judge (ALJ) Cooke in Rulemaking (R.) 02-06-001. That Ruling stated:

> We believe the time is now to consider adoption of a new default rate (or rates), tailored to customers with demand over 200 kW, that provides a critical peak price (CPP) signal distinct from the generic peak period. We direct PG&E, SCE, and SDG&E to file applications by January 20, 2005, for implementation by June 1, 2005, that propose new rate schedules for all customers over 200 kW that provide strong peak demand signals… The proposed tariffs should

> be designed to recover the total revenue, including transmission and distribution charges, currently allocated to customers 200 kW and larger and be class revenue neutral, compared to existing rates, based on current class load patterns. (Ruling pp. 2-3.)

As any party who has been following this proceeding or the electricity industry generally should be aware, there is substantial concern in the regulatory community that during the Summer of 2005 there may be insufficient generating capacity to meet system peak demand. The Commission has attacked this problem in various ways, increasing efforts in the areas of energy efficiency, demand response, and generation supply among others, especially in Southern California. Despite an improved outlook prepared in February 2005,[1] the California Independent System Operator[2] remains concerned about tight supplies in Southern California under hot weather conditions (1-in-10-year forecasts) and in Northern California because of lower than normal snow pack in the Pacific Northwest.

Seeking to add additional tools by which we could attack the problem of high peak demands, President Peevey and assigned ALJ Cooke issued the ruling, referenced above, in our rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing. In directing the utilities to file applications for a new default rate with critical peak features, they sought to address some of the problems that we have experienced in that rulemaking,

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[1] This report was referred to by several parties in testimony. It can be found at http://www.energy.ca.gov/electricity/2005_summer_forecast/2005-02-22_senate_presentation.pdf.

[2] When referring to a position taken by the California Independent System Operator we refer to the organization as the CAISO. When referring to a procedure, rule, or process employed by the CAISO Operator we utilize the term ISO.

including a lack of enrollment by large customers in voluntary demand response programs, and limited performance by customers who have enrolled in certain programs. Because customers 200 kW and above are the only customers with metering and communications infrastructure in place to record and monitor the impacts of rates on peak load, they targeted the large customer classes, even though they recognized that these customers might not have significant amounts of discretionary load during peak periods and do not necessarily drive the summer peak.

On January 20, 2005, PG&E, SCE, and SDG&E filed their applications. Testimony by 17 parties followed on February 16, with rebuttal testimony on February 22. Evidentiary hearings took place on February 24 through March 1, 2005. The Assigned Commissioner issued his Scoping Memo on March 11, 2005. Opening briefs were submitted on March 14, reply briefs on March 21, and this proposed decision issued, for a shortened comment period, on March 28, 2005. This extremely expedited schedule was necessary and appropriate because of the need for the Commission to adopt a decision by April 21, 2005 if a new rate were to be in place by June 1, 2005 as called for in the December 8, 2004 Ruling. We affirm the ALJ's decision to shorten the comment period on the proposed decision in order to allow for a decision to be rendered in time to implement rates by June 1, 2005.

On March 8, 2005, the Silicon Valley Manufacturer's Group (SVMG) filed a motion to intervene. By this decision we grant the motion and affirm the admission of late-served testimony by SVMG on March 23, 2005. On March 14, 2005, the California Hospital Association and the California Society for Healthcare Engineering (collectively CHA / CSHE) filed a motion to intervene in order to file briefs. The motion is granted. Any other outstanding motions are denied.

Requests for Final Oral Argument was made by PG&E and the California League of Food Processors (CLFP) on March 14, 2005.

3. The Proposals Presented

The ruling in R.02-06-001 directed that the proposed tariffs should be designed to recover the total revenue, including transmission and distribution charges, currently allocated to customers 200 kW and larger and be class revenue neutral, compared to existing rates, based on current class load patterns.[3] In addition, the utilities were to include customers currently receiving service under interruptible/non-firm rate schedules on the new tariffs and migrate those customers onto an alternative interruptible program called E-BIP (for Base Interruptible Program) that makes a capacity reservation payment to participating customers rather than offering lower rates like the non-firm rate schedules provide.

Each utility responded to these directives by proposing different structures for their default critical peak pricing tariff. The Office of Ratepayer Advocates (ORA) also made a specific proposal in testimony. Below we provide a brief comparison of the critical features of each utility and ORA's primary proposals.

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[3] In other words, the new default rate proposals were to be comprehensive, covering both demand and volumetric charges.

	PG&E Preferred	SCE	SDG&E	ORA Preferred
Customer Applicability	200 kW – 500kW firm customers exclude DA/ag, optional for interruptible tariffs	>200kW firm customers, exclude direct access (DA)	>300kW with access to kWickview, includes DA	All customers over 200 kW, including non-firm.
Critical Peak Price[4]	$0.25/kWh adder to tariff rate	$1.00/kWh	11am-3pm: $0.13906 3pm-6pm: $0.28065	Not calculated but based on generation marginal capacity cost. Eliminate current generation summer peak demand charge for firm customers. For non-firm customers, split the current summer on-peak energy charge into CPP and non-CPP charges.
Non-Critical Peak Credits[5]	$0.42 – 0.066/kWh credit applied to partial and off-peak usage within same day as event call	14-18% credit, per event called, applied to on- peak energy and demand charges within billing cycle	$0.08914/kWh peak $0.06512/kWh semi/off-peak	Not calculated

[4] PG&E’s on-peak secondary voltage total energy rate for E-19V is $0.14657, and for A-10 is $0.14036.

	PG&E Preferred	SCE	SDG&E	ORA Preferred
Hedge Premium	$0.001/kWh for all summer kWh	1.93 – 15.12% increase applied to all summer on-peak charges (varies by rate schedule)	5% premium on commodity portion of current summer rates, $0.10423/kWh on-peak $0.07901/kWh semi/off-peak become new rates	Not calculated
Participation Credit	$0.001/kWh credit	None	None	None
Event Duration	3 hours/event, 3-6 pm	6 hours/event, noon-6 pm	7 hours/event, 11am – 6 pm	
Triggering Event	Statewide standard that makes use of "best available day-ahead forecast information"	ISO Alert	ISO Alert; SDG&E system and temperature conditions; SDG&E grid emergencies	Prefer SDG&E's proposed trigger, based on system reserves.
Customer Notification	3pm day before	3pm day before	3 pm day before	Not stated

[5] Credits are presented as ranges because they vary based on rate schedule for PG&E and SCE. For SDG&E, when no event is called, the rates set forth in this row apply. (See generally Exhibits 1:4-6, 5:19, and 9: Attachment C.)

	PG&E Preferred	SCE	SDG&E	ORA Preferred
Event Call Limit	12 days (36 hours)	15 days (90 hours)	12 days (84 hours)	12 days
Range of Bill Impacts[6]	-3.88% to + 3.17%, assuming no change in load and 12 calls	-40.68% to + 16.11% assuming no change in load and 12 calls	-6.12% to +4.88% assuming no change in load and 12 calls	Not calculated
Opt-Out Deadline	None established	June 5, 2005	May 15, 2005	Not stated
Implementation Costs	$7,167,500	$2,009,700	$1,273,000	Not stated
Outreach	Encourage customer feedback through the regulatory process education and marketing	Education and outreach; "information and tools"	Contact / inform; Market load control tech. incentives	Not stated

[6] Derived from Exhibits 22, 12 and 14.

As is evident from this table, the proposed rate designs are very different. This means that a customer who has facilities in different utility service territories would need to approach its facility management differently based on who the facility takes service from, complicating the customer's energy management planning process. In addition, each utility took a different approach to whether to exclude certain types of customers from the default tariff. For example, PG&E would exclude customers taking service under agricultural tariffs, but SCE would not. It addition, although the utilities complied with the December Ruling in filing the applications, none supports implementing the proposed rates in Summer 2005.

4. The Parties' Positions

As we would expect when considering a significant change in rate design, the December 8, 2004 Ruling and ensuing utility applications generated a significant amount of customer comment, almost all of it negative. We briefly summarize the positions of each affected customer type that participated, as set forth in their testimony, under cross-examination, and in briefs.

4.1 Commercial/Retail Building Operators

The BOMA[7] argues there is no evidence CPP will be effective in reducing peak demand. BOMA points to a Working Group 2 Evaluation (Dec. 21, 2004)

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7 BOMA of San Francisco (BOMA SF) members own and manage buildings in SF, San Mateo, Marin, and Sonoma counties. BOMA SF estimates that average demand is about 4.9 W/square foot with 35 buildings less than 200 kW; 62 between 200 kW and 500 kW; and 162 greater than 500 kW. Over 90% of peak demand belongs to accounts that are >500 kW. The buildings house primarily small and medium size businesses. During the hearings BOMA California joined with BOMA SF to participate, so we designate their combined participation simply as BOMA.

that found voluntary CPP yielded disappointing results. BOMA believes that in order to be effective, CPP must induce new investment in building controls but the prohibition on commercial sub-metering (found in Tariff Rule 18) impedes progress in this area for building owners because it prohibits exposing tenants to time of use (TOU) rates. BOMA is concerned that the utility proposals are not cost based and will result in a wealth transfer from peaky users (office buildings) to flat profile users (grocery stores, hotels, etc.), and from inland users to coastal users. BOMA notes that peaky load curves are inherent for office buildings, and not a sign of inefficiency. BOMA points out that many BOMA SF buildings have won Flex Your Power and Energy Star awards for their energy efficiency. Finally, BOMA argues that PG&E faces no emergency capacity shortage and should not have a default CPP implemented to address a Southern California problem.

The Indicated Commercial Parties (ICP)[8] believe any critical peak pricing program should be voluntary, not mandatory. ICP believes implementing a mandatory rate for Summer 2005 will hamper subsequent program modification and will worsen California's business reputation. They argue that the proposed bill impacts are so small that they will not induce behavioral changes. For example, ICP argues that for SDG&E, very few customers will have bill impact greater than 2%. ICP states that since a typical 300-500 kW customer's bill is $200,000, the bill would be raised at most by $4,000, less than the cost of training

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[8] The ICP is made up of the County of Los Angeles, Lowe's Home Improvement Warehouse, and Catholic Healthcare West. Most accounts at CHW hospitals exceed 500 kW but most hospitals have multiple, smaller accounts, too. Two thirds of LA County's 120 commercial accounts are between 200 kW and 500 kW. The remaining accounts account for 75% of load. Most Lowe's accounts exceed 500 kW.

a building manager how to respond. ICP believes that if the Commission decides to pursue a new default tariff, ease of use is critical to success which means making the program uniform statewide with respect to trigger events, duration of periods, maximum number of events, notice timing, CPP price, crediting back and accounting, and any hedging premium cost.

Costco Wholesale (Costco) states that although the utilities' proposals differ from each other in important ways, but all would impose inequitable penalties without being effective in lowering demand. Since customers can't make meaningful critical peak period demand reductions, many will "opt out" and thus contribute nothing to demand reduction.

For example, Costco argues that SCE's program is confusing, but apparently would force Costco to reduce critical peak usage by 17% (far in excess of anything possible) in order to stay bill-neutral at a given facility. According to Costco, if it didn't opt out, its bill might increase by up to $380,000/year at that facility. SDG&E's proposal would require Costco to reduce critical peak period load by 7% (also in excess of what Costco states it can achieve) to stay bill-neutral. Costco's exposure under the SDG&E tariff is much less -- $13,000 – as a result of the more moderate CPP rate. To opt out would cost $91,000. Because PG&E's proposal doesn't apply to the tariff schedule that Costco takes service under, it has no impact on Costco. Costco states it has already done a lot to reduce its usage by employing energy efficiency measures, setting store thermostats high, minimizing use of outdoor and indoor light during peak periods, and installing ice storage as a peak shifting technique for new construction. Costco believes additional changes would compromise food safety.

Costco suggests that if the Commission wants to reduce demand it should eliminate any bill increase to customer that lowers its demand by 3% in critical peak periods, limit each event to four hours, and provide positive incentives, such as assistance to invest in ice storage. "Customer-specific revenue neutrality for 3% load reductions would ensure that customers are protected from the increased default CPP rate if they contribute pro rata to the Commission's established goal of a 3% reduction in critical peak period demand for 2005. [Footnote omitted.] Such a clear incentive would increase participation in the Default CPP Program." (Costco Opening Brief, p. 13.)

Wal-Mart[9] does not believe the utilities' proposals meet the December 8, 2004 Ruling's goal of "predictably and systematically" moving large customers' usage out of their critical peak period. Wal-Mart would reject the utility proposals, finding them watered down from what the Ruling required, and order them to file new ones. Wal-Mart recommends the adopted rates be permanent rather than just for one summer because customers need time to plan, develop, and implement price-responsive measures, otherwise, the rates will be only punitive. Wal-Mart prefers SDG&E's approach of a totally new tariff, rather than a rider over the pre-existing tariff.

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9 There are 192 retail Wal-Mart facilities in CA (148 Wal-Mart stores, 3 Wal-Mart Supercenters, 33 Sams' Clubs, and 8 distribution centers), with 65,879 "associates," consuming more than 500 million kWh, both bundled and direct access.

J.C. Penney[10] agrees with Wal-Mart's position. California Retailers Association (CRA)[11] brief echoes many of the concerns raised by BOMA, Costco and Wal-Mart in testimony.

CHA/CSHE[12] recommends that the Commission exempt hospitals and health care facilities from mandatory application of CPP tariffs, without an additional hedging premium. They prefer that existing time-of-use schedules remain the default for customers above 200 kW with positive financial incentives offered to customers with high demand elasticity to encourage any desired load shifting. "CHA/CSHE believes that the first step in the process to develop a new rate design for the large customer class is to realign all customers' rates more closely with cost of service. Inter-class subsidies should be addressed in the cost allocation proceeding of a General Rate Case (GRC), which needs to precede any efforts to move forward with a CPP or a Real Time Pricing rate structure." (CHA/CSHE Opening Brief, p. 5.)

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[10] J.C. Penny operates 1,020 department stores in U.S. and 93 stores and other facilities in CA, consuming over 120 million kWh/yr. in bundled service.

[11] CRA's membership is comprised of major California department and specialty stores, mass merchandisers, grocery, chain drug and convenience stores that are located within the service territories of PG&E, SCE, and SDG&E. Its members consist of both bundled electric utility customers and Direct Access ("DA") customers who typically take service under utility tariffs applicable to medium and large commercial customers, many of whom with demand between 200 KW and 500 kW.

[12] The California Hospital Association represents 400 hospitals and health systems in California. The California Society of Healthcare Engineering represents 800 individuals with an interest in health care engineering.

4.2 Large Manufacturing and Industrial Customers

Electricity costs are very significant part of operating costs for California Large Energy Consumers Association (CLECA)[13] members who have already made major investments in response to utility rates and interruptible rates. These prior efforts will make it difficult to make additional demand response available for Summer 2005.

In critiquing the utility proposals and the general concept of a critical peak pricing default tariff, CLECA focuses on two principles:

- Equity: don't attempt to get more reductions from customers whose loads are not peaky;
- Effectiveness: will the program work to reduce load?

CLECA argues that because 29% of peak load is from air conditioning, and 11% is from commercial lighting, customers under 200 kW and between 200 and 500 kW are more likely the drivers of high peak demand than industrial customers. CLECA suggests that more demand reduction is achievable by focusing on users of air conditioning and commercial lighting between 200-500 kW now that they all have interval meters. CLECA also suggests that the Commission consider targeting customers with loads of less than 200 kW, agreeing with SDG&E that price signals achieve the most response when implemented across all customer groups. CLECA supports PG&E's exemption of

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[13] Each CLECA member's load exceeds 5 MW. CLECA represents high load factor and high voltage industrial customers of PG&E and SCE in the steel, cement, beverage, and air products industries that operate 24/7 and electricity is a very significant part of operating costs. Most CLECA members take interruptible service and have done so for two decades. Some CLECA members take bundled service, but some are direct access.

non-firm and interruptible customers because reliability programs are the "last bastion of defense against the curtailment of load."

CLECA sets forth certain rate designs elements that any default tariff should adhere to. For example, the rates should be:

- Based on cost of service with marginal generation capacity cost reflected in summer on-peak, partial-peak and winter partial-peak demand charges rather than in both demand and energy charges.
- Credit customers in the same billing cycle, to the demand component of energy charges during all TOU periods.
- Triggered locally, rather than statewide.

California Manufacturers and Technology Association (CMTA)[14] opposes implementation of a new default tariff for summer 2005, arguing that implementation will do more harm than good. CMTA emphasizes that stability and predictability in rate design should be emphasized because this allows for real long-term shifts in physical plant and operating practices. According to CMTA, most customers need at least six months to respond to new programs. For large customers, energy efficiency expenditures are often part of an annual program and budgeting process.

If the Commission does implement a new default tariff it should apply only to firm bundled customers who are not participating in other demand response or reliability programs and have loads between 200 and 500 kW since

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[14] CMTA represents 500 companies, located in service territories of all three electric utilities, with bundled and direct access arrangements, on firm and non-firm schedules.

many DA contracts already provide market price signals and provide a reliability benefit. CMTA states that customers with load greater than 500 kW:

- have minimal air conditioning load, and thus contribute less than average to system peak;
- have generally been on TOU rates for 20 years, which, because of the predictability and stability of the rates have sent stronger price signals than the CPP rate would;
- have already made very significant efficiency gains; and
- cannot easily shift or curtail load.

If the Commission wishes to pursue a default tariff with a CPP type structure, CMTA recommends that whenever possible, programs should be uniform across California and called only when needed based on an ISO Alert for that zone. CMTA opposes calling the program for testing or information gathering purposes and would cap the number of events per season at not more than 15. CMTA encourages the Commission to set rates at no more than peak market prices, currently about $0.25/kWh and establish a reasonable opt out rate if one is adopted. CMTA considers even PG&E's proposed $0.001/kWh premium to be onerous. CMTA would have any credits from the higher critical period price returned to customers during other on-peak periods.

CMTA suggests that the rate be a rider, like PG&E and SCE have proposed, rather than an entirely new rate because a rate rider is more logical for customers to understand. In addition, CMTA believes that revenues collected during a CPP event should be returned to customers in a manner that minimizes customer bill impacts and maintains customer revenue neutrality.

CMTA offers several utility specific critiques. For example, CMTA finds that SDG&E's 5% hedging premium is much too high. Because of the way the SDG&E rate is structured, if less than 12 events are called, the program will result in an undercollection in the revenue requirement, which CMTA finds problematic. CMTA would also like to see cancelled CPP events counted towards the cap on the number of called events which neither SDG&E or SCE do. Regarding SCE's proposal, CMTA argues that the critical peak price proposed by SCE ($1.00/kWh) is excessive and not connected to market prices. Because of this, the bill impacts of SCE's proposal on individual customers are excessive. CMTA provides the example that even if some customers reduced their demand by 5% during critical peak periods they'd still see bill increases. CMTA also finds fault with SCE retaining a 6 hour peak period, rather than a shortened 3 hour period like SDG&E and PG&E. CMTA argues that PG&E's proposal isn't revenue-neutral.

SVMG[15] proposes that the utility's annual generating costs be divided into three buckets: (1) the highest 1% of on-peak hours: (2) the remaining hours designated "on-peak" – about 18% of the year (noon-6 pm weekdays); and (3) the remaining 81% of the hours of the year. SVMG proposes that all annual capacity costs be included in and recovered through charges to the 1% bucket. Under SVMG's proposal, each cost bucket is divided by the anticipated number of kWh for the hours specified, which determines the generation cost per kWh for critical

[15] SVMG represents nearly 200 Silicon Valley employers who provide over 200,000 local jobs. Membership is open to Silicon Valley firms and supporting industries including software, systems, manufacturing, financial services, accounting, transportation, health care, defense, communications, education, and utilities.

peak, on-peak and off-peak. SVMG would trigger CPP events based on a CAISO system peak forecast of 97% of its highest peak estimate made before the summer season begins.

Energy Producers and Users Coalition (EPUC)[16] focuses on the lack of rationale for requiring SCE and PG&E to implement CPP rates for Summer 2005. Specifically, EPUC argues that industrial customers who may not be able to shift load will be "singled out for punitive rate treatment vis-a-vis other customer classes." EPUC doesn't believe a showing has been made that the proposed CPP program will result in meaningful load reductions, while eliminating existing non-firm and interruptible programs could be detrimental to system reliability.

Although EPUC recommends against instituting default CPP for Summer 2005, if the Commission does implement default CPP for summer of 2005, then it should also expand non-firm and interruptible programs and exclude customers larger than 500 kW from participation. EPUC submitted 5-year average data that shows that large customers (on Schedules E-19 and E-20 for PG&E and Schedules GS-1, TOU-GS-2, and TOU-8 for SCE) generally have flat demand curves, compared to residential customers. To EPUC this data calls into question the efficacy of CPP rates in getting large customers to actually suspend their core business activity to remove power from the peak, and equity given that large customers do not drive peak demand.

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[16] EPUC members are Aera Energy LLC, BP America, Chevron, Conoco Phillips, ExxonMobil Power and Gas Services; Shell Oil Products US, THUMS Long Beach Co., Occidental Elk Hills, and Valero Refining Co. CA.

4.3 Agricultural Interests

As a preliminary matter, Agricultural Energy Consumers Association (AECA)[17] supports PG&E's proposal, which exempts agricultural customers, "given the lack of significant air conditioning load and the general unsuitability of a CPP Program rate for this customer group." (Ex 1, p. 3-11:7-8.) If implemented, AECA prefers PG&E's approach of crediting off-peak usage within the same 24 hour period on CPP days. AECA argues that agricultural activity cannot be put off to another time of the year, irrigation users are often constrained as to when they are allowed to pump, so they cannot switch out of the peak period, and irrigation must often be operated for 24 hours straight without interruption.

AECA notes that given these constraints, the only way a farmer can move off the peak period is to invest in new pumps and equipment, which does not make financial sense when a program is only called the day ahead, although AECA concedes that it might make sense if the rate were more like a time-of-use rate. AECA also points out that unlike a commercial building, farming is not amenable to centrally controlled instantaneous energy management because turning pumps on and off must be done in the field rather than near a phone. AECA opposes SCE's approach of crediting only on-peak charges arguing that by lowering rates on non-critical days, demand on those days is encouraged, and might boost demand, resulting in more critical days being triggered. In addition,

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[17] AECA is a non-profit founded in 1991 by growers and other members of the agricultural community in all three service territories and represents the collective interests of many agricultural associations, several farm bureaus, and 42 agricultural water districts.

AECA suggests that instead of calculating any hedging premium by comparing the customer's load profile against others within the rate class as SCE did, the comparison should be against an overall customer load profile that encompasses all customer classes so that a customer class that has moved its load substantially off peak will not be penalized. (AECA Opening Brief, p. 5.)

Like AECA, California Farm Bureau (Farm Bureau)[18] supports PG&E's exemption of agricultural customers even though most agricultural customers' loads are less than 200 kW so very few are subject to the default CPP proposals. Like BOMA, Farm Bureau points out that adoption of a default CPP provides no certainty of demand reduction (because CAISO doesn't consider demand response to be a resource), thus it provides no reliability benefit and no benefit from reduction in procurement requirements. Farm Bureau argues that part of the problem the Commission seems to be addressing is apparently a transmission shortage, so direct access customers should also participate in a program, if adopted.[19]

Farm Bureau identifies the lack of time to decide whether to opt out and pay a hedge premium as problematic, and states that customers need more time than is provided under the utility proposals to decide whether or not to stay on the CPP rate or pay a premium to remain on the old rate. Farm Bureau considers the hedge premium to be a penalty to force customers to stay on the new default rate.

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[18] Farm Bureau is made up of county farm bureaus that collectively represent about 75 percent of California's farmers and ranchers. (RT 471.)

[19] Farm Bureau suggests that only direct access customers who have power supplies located inside the constrained territory should be exempted.

California League of Food Processors (CLFP)[20] explains that at harvest time, food processors operate 24/7 at full capacity and CLFP is concerned that adoption of a CPP default rate could temporarily shut down food production, which would not be recoverable for the industry. Because of the way accounts are structured, there are hundreds of food processing loads less than 500 kW and could be affected, even if the applicability were narrowed to 200-500 kW.

4.4 School Districts

Los Angeles Unified School District (LAUSD)[21] argues it must be exempted from a new default tariff because of budget and operating constraints it faces. LAUSD indicates that 85% of its schools are on non-traditional schedule, i.e., open all summer and provide significant afternoon after school programs. LAUSD states that it cannot pass on increased energy costs, turn off lights, or run schools at night. Its alternative would be to shut schools. LAUSD believe it should be exempted from CPP because if SCE charges $1/kWh for energy it could face increased costs of $432,000/year, but the hedging premium is also not affordable.[22]

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[20] Most food processors have several accounts, exceeding 500 kW. On an aggregated basis, food processors can reach loads of 4-6 megawatt (MW).

[21] LAUSD has more than 1,000 campuses with 275 accounts, of which 60 are greater than 200 kW, of which most procure direct access energy. The peak demand of all LAUSD facilities in SCE territory is 18,000 kW. 22 accounts with approximately 2 MWs of load, would be subject to SCE's proposed CPP.

[22] SCE notes on brief that this figure did not reflect the reduction in charges that would occur during non-critical peak hours.

4.5 Transit Systems

Bay Area Rapid Transit District (BART)[23] seeks an exemption from a default critical peak tariff if one is adopted for customers of its size. BART's demand is about 84,000 kW, thus it would exempt from PG&E's proposal (which limits the applicability of the tariff to customers with less than 500 kW in load), but BART is participating in the event that the Commission considers adoption of SCE's or SDG&E's proposals, which have no upper demand limit on customer applicability.

BART notes that 3 to 6 pm, the focus of PG&E's proposals, corresponds to BART's peak usage (the evening rush hour) and would likely be called on high-pollution ("Spare the Air") days, when trains are in especially high demand. BART states that, on an energy-equivalent basis, BART moves people at about 250 miles per gallon (mpg), about 10 times as much as cars while substantially relieving road congestion.

4.6 Petroleum Producers and Transporters

While the California Independent Petroleum Association (CIPA) and California Oil Producers Electric Cooperative (COPE)[24] appreciate the sentiment and concept of CPP, they believe there is danger that implementation will curtail

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[23] BART is a local government agency, located entirely in PG&E territory. BART purchases "federal preference power" under terms set in 1996 by the California Legislature and codified in Pub. Util. Code § 701.8. Accordingly, BART is not a direct access customer, but it also does not purchase power from its local regulated utility, and takes only distribution service from PG&E. BART is therefore not a bundled service customer.

[24] CIPA represents >400 companies in CA. COPE provides energy services for more than 50 of most prominent independent producers. Members represent 2,000 MW.

business activity of oil producers because a significant proportion of oil operations require constant energy use and cannot be cycled. CIPA/COPE recommends that the Commission consider adopting different rates for different customer types and keeping rates voluntary. CIPA/COPE also suggests that if capacity concerns are in Southern California, PG&E customers should not be required to participate. CIPA/COPE also states that if demand reduction is a goal, more effective distributed generation efforts (through R.04-03-017) would be useful. CIPA/COPE believes their industry is particularly well suited to employing distributed generation.

Kinder Morgan Energy Partners L.P. (KM)[25] opposes adoption of the proposed default tariffs and encourages the Commission to focus on expanding existing interruptible demand programs.

4.7 Generation Interests

Independent Energy Producers Association (IEP) seeks to call attention to an inadvertent impact of default CPP. IEP notes that some electric generators take electric service for start up power and by establishing a CPP default tariff the Commission might discourage generators from starting up during peak periods. IEP recommends that generators should be exempt from any default CPP tariff.

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[25] KM's 10,000 miles of pipelines and associated terminals transport more than two million barrels per day of gasoline, jet fuel, diesel fuel and natural gas liquids. KM operations in California are spread across approximately 300 individual accounts, about 20 with loads in excess of 500 kW; about 10 in the 200-500 kW ranges; and the balance have peak demands of less than 200 kW. Approximately 90% of KM's total load is Non-Firm and approximately 90% of KM's load is DA, 95% of KM's load is split evenly between SCE and PG&E's service territory, with only one account with SDG&E that is greater than 200 kW.

Western Power Trading Forum (WPTF)[26] agrees with the December Ruling's concerns about supply capacity adequacy and with pursuing aggressive CPP approaches but it echoes concerns voiced by IEP, that any adopted default CPP tariff should exempt generators.

4.8 Demand Response/Advanced Metering Companies

The California Consumer Empowerment Alliance (CCEA)[27] supports the principle that CPP tariffs should be entirely voluntary, including with customers having the option to return to their previous time-of-use tariff, with no additional premium. CCEA suggests that the costs associated with switching tariffs exceed the economic impact of switching for the vast majority of customers and thus if CPP were to make CPP the default tariff many more customers would remain on the tariff than if they had to opt-in. CCEA cites market research conducted on residential customers in the Statewide Pricing Pilot that estimated that 67 to 92 percent of customers would participate in a default CPP rate program, while only 10 to 34 percent would participate in an opt-in program.[28] CCEA also recommends that any rates adopted be cost based.

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[26] WPTF is lobbying group promoting competitive power markets. Members are Electric Service Providers (ESPs), scheduling coordinators, energy consultants, and public utilities.

[27] The membership of CCEA includes numerous demand response and advanced metering technology, software, and services companies.

[28] Momentum, "Customer Preference Customer Preferences Market Research (CPMR): A Market Assessment of Time-Differentiated Rates among Residential Customers in California," June 2004.

4.9 CAISO

The CAISO's focus in these proceedings was to ensure that the existing interruptible programs be protected and expanded where appropriate. The CAISO also recommended that the appropriate trigger for a CPP event be an ISO Alert Notice and that an event be triggered for the 2:00-6:00 p.m. period, rather than any of the time periods recommended by the utilities.

4.10 Small Customer Interests

ORA starts from the premise that CPP is a form of dynamic pricing that may produce reliability benefits, but it should not be seen per se as a reliability program, because there is no guarantee of how customers will respond. ORA views CPP as a step between TOU and Real Time Pricing (RTP). ORA would exclude DA customers from default CPP, since they procure their own generation, but would not exempt non-firm customers.

ORA believes the utilities want reliability impact from CPP, but the relationship between critical and non-critical on-peak prices in their proposals is arbitrary, not cost-based, and constrained by bill impacts. As ORA points out, a bigger critical to non-critical price differential would have more demand impact, but its bill impacts would be severe. ORA prefers CPP prices to TOU prices because CPP prices are dynamic, whereas TOU prices are static and have diluted price signals. ORA suggests that this is an excellent time to introduce CPP pricing, not because it will guarantee load reductions this coming summer, but because we need to begin the transition to dynamic pricing now.

ORA believes CPP rate design should be cost-based and revenue-neutral, and based on generation marginal capacity revenues. For firm customers, the current generation summer peak demand charge should be eliminated, since those revenues will be collected through the CPP energy rate. For non-firm customers, splitting the current summer on-peak energy charge into CPP and non-CPP on-peak charges should produce the CPP rate. Customers will pay the generation demand charge and receive a per kW discount.

ORA recommends that CPP triggers match forecasts that drive procurement decisions and rate design assumptions with other triggers, like ISO Alerts or temperature triggers supplementing the procurement drivers. ORA finds SDG&E's proposal to base the trigger on its estimation of system reserve requirements instead of on ISO Alerts the best proposal presented.

ORA recommends that the principles underlying the voluntary CPP tariff in the SCE GRC settlement be used to design the default tariff. For both PG&E and SCE firm customers, ORA would divide the marginal generation capacity revenues (with no equal percentage of marginal cost scaling) by super-peak energy usage and add this to the peak generation energy charges. The generation energy charge would be calculated on a residual basis to recover total allocated generation revenue less the marginal generation capacity revenues with no generation demand charge. For non-firm customers, TOU peak energy charges would be subdivided into peak and super-peak components based only on the marginal energy cost differentials in the two periods. All marginal capacity costs are recovered in demand charges as they are currently recovered in existing TOU rates. ORA finds SCE's design problematic because during CPP events, customers would be paying the marginal generation cost twice, in both the CPP energy charge and in the generation summer peak demand charge. ORA recommends adopting SDG&E's proposal for Summer 2005 but using (for SDG&E only) principles described above for subsequent rate design.

The Utility Reform Network (TURN) concedes that because this proceeding focuses on large customer rates within existing cost allocation, the utility proposals do not affect residential or small commercial customers. However, TURN offers its observations concerning some of the global policy issues related to dynamic tariffs, rate design, and demand response that it believes could influence the Commission's treatment of rate design for its constituents. TURN would rather see the Commission focus on improving existing energy efficiency and demand response programs, than pursue these rate design applications. TURN is concerned that rushed implementation without significant lead time may produce more harm than good in the long run.

If the Commission does adopt a default critical peak pricing tariff, TURN suggests that any revenue shortfalls and program costs should be shared by all retail (bundled and direct access) customers, and should be allocated using a generation allocator because all customers benefit from reliability improvements, which is what TURN sees as driving this proceeding. TURN also argues that there is no basis provided thus far to exclude customers over 500 kW from participation, if the Commission goes forward. In fact, TURN argues, even CLECA's witness stated that historical value-of-service analyses have shown commercial load to be less price elastic than industrial load. (RT 416, Barkovich.)

5. Issues Presented

This proceeding presents several key issues.

5.1 Will implementation of critical peak pricing tariffs result in demand reduction for Summer 2005?

First and foremost, the intent in pursuing a new default tariff with critical peak prices and under the rapid schedule set forth in the December Ruling was to accomplish demand response for Summer 2005. Therefore, we must first assess what level of demand reduction might reasonably be expected before deciding whether to move forward. To do that, we assess the existing summer peak loads for customers over 200kW.

PG&E has bundled load (excluding non-firm load) of about **3,400 MW.**[29] (RT 166:14-17 and Exhibit 26.) SCE has coincident summer peak bundled load (excluding interruptible) of about **3,042 MW.** (Exh. 12.) SDG&E has about **835 MW** of peak load for customers over 300 kW. (RT 338:4-5.[30])

Next, we must determine the maximum projected demand reduction for these customers. PG&E utilized a set of assumptions to establish an upper bound of possible demand reduction. PG&E assumed **1,800 MW** of the peak load would actively manage demand in response to prices and that entire 1,800 MW reduces load by 5% during the critical peak. The resulting upper bound of load reduction is **90 MW**. (RT 166:23-167:12.) Using PG&E assumptions of approximately 50% of peak load actively managing demand in response to prices and load reductions of 5% during critical peak, SCE's expected upper bound of demand response is **76 MW**. SDG&E assumes 2.4% to 3.4% load reduction from total peak load, resulting in potential reduction of **20-28 MW.** (Exhibit 7, Chapter 1, Attachment A.) Using these upper bound figures, the total maximum load reduction we might expect from implementing a critical peak demand tariff for customers over 200 kW is **186-194** MW statewide, with 96-104 MW of that amount in Southern California.

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[29] As pointed out by TURN in comments on the proposed decision, unless otherwise specified, all of the load figures discussed in this section **exclude** direct access load and interruptible load.

[30] Based on subsequent information provided by SDG&E, it appears that this peak load forecast is for customers over 200 kW, not 300 kW. SDG&E projects 2005 peak demand for customers with more than 200 kW load at 860 MW. (See Exhibit 27.)

If we were to narrow the applicability of the new default tariff to loads only between 200 kW and 500 kW, as suggested by many parties, the maximum, upper bound figure declines significantly. For example, PG&E bundled load between 200 and 500 kW is about 900 MW. (RT 166:17-19.) Using PG&E upper bound assumptions, we would estimate that 450 MW of load is actively managing demand in response to prices and that entire 450 MW reduces load by 5% during the critical peak with a resulting upper bound of demand reduction of customers between 200 and 500 kW of 22.5 MW. If we narrow the applicability for SCE and SDG&E to just 200 – 500 kW customers the summer peak load for these customers is 1,424 MW[31] and 327 MW[32] respectively, which results in a maximum projected load reduction of 35.6 MW and 8.2 MW respectively. Thus, using these upper bound figures, the total maximum load reduction we might expect from implementing a critical peak demand tariff for customers between 200 and 500 kW is 66.3 MW statewide, with 43.8 MW of that amount in Southern California.

Because of the structural framework for the proposed rates and the focus on energy rather than demand, customers who see a bill increase if they do not modify their on-peak usage have very little ability to mitigate that bill impact even with significant change in usage. For example, for SDG&E, only 9 of its 998 customers that are 300 kW or above would be expected to see their bills increase

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[31] Exhibit 12 lists the average 2003 coincident peak demand as 1,278 MW for Schedule GS-2 (200 – 500 kW). Exhibit 28 clarified that at the actual time if system peak the relevant customer group's load was 1,424 MW.

[32] This is the figure provided by SDG&E for 200 kW – 500 kW load customer in Exhibit 27.

by more than 3% if they made no load reduction efforts. However, the customers whose bills do increase, would not see commensurate reduction in their bills, even if they made significant demand reductions. An example for SDG&E can be found in Exhibit 14 with Assembly Industry Sample 3. Using historical load data for this actual customer, SDG&E shows the customer would see an increase of 3.66% to its summer bill if SDG&E's proposed rates were implemented and it made no changes to its usage. If it reduced its usage on peak by 5%, its bill would still increase by 3.34% compared to current rates. For this customer, a 5% reduction in use results in a 0.32% reduction in its bill compared to taking no action, not a strong motivator to reduce peak demand on critical event days.

SCE's data shows similar results to SDG&E. For SCE, Exhibit 6, Appendix A shows that with the exception of agricultural, pumping and refrigeration loads, 94% of customers of all other building types would see bill increases of less than 6%, with most bill increases between 0-2%, when four critical peak events are called. However, those customers with significant bill impacts for SCE would generally only see their bill go down by less than 1% for each 5% reduction in peak load they make. (See generally Exhibit 12.) PG&E's analysis also shows that bill impacts for most customers under its proposal will be limited to +/-1%, with nearly all customer bill impacts limited to +/-2%. (See Exhibit 4, Attachment 4, pp. 5-7.) For PG&E, a 5% reduction in use generally results in less than a 0.50% reduction in its bill compared to taking no action. (See generally Exhibit 22.)

Given the bill impacts for customers whose bills increase if they do not modify their loads, we find that the upper bound assumptions that 50% of the applicable customer load will manage their demand in response to the rate, and that every customer that does actively manage their load will reduce their usage by 5%, to be quite aggressive assumptions. The timing concerns raised by parties, especially for customers in the 200 to 500 kW size that do not have account representatives, also factors into this finding. Because the bill impact from modifying usage is quite limited, the rate designs do not provide a strong motivation for customers to change their on peak usage, since they will still be worse off. More reasonable assumptions would result in lower expected demand reductions. If instead we assumed that 10% of the applicable customer load actively manages their load and achieves a 5% reduction, the expected load reduction for all firm bundled customers with load over 200 kW would be 17 MW for PG&E, is 15 MW for SCE, and 4 MW for SDG&E, or 36 MW statewide. If the customer applicability were limited to firm bundled customers between 200 and 500 kW, the expected load reduction would be 4.5 MW for PG&E, 7.1 MW for SCE, and 1.6 MW for SDG&E, or 13.2 MW statewide.

We emphasize that these findings relate specifically to implementing the rates proposed in these applications on the accelerated schedule that would be necessary to implement such rates by June 1, 2005. These findings have limited value for predicting longer term ability of customers to respond to rate changes or rate structures that would occur over time.

5.2 From a policy standpoint, should any customers with loads of 200 kW and above be exempted from critical peak pricing rates in Summer 2005?

Here, we consider whether any customers should be exempt from a default critical peak rate for Summer 2005. The December Ruling indicated an intent that all customers, including those on interruptible/non-firm rates would be subject to the new tariff for the summer. We continue to believe that all customers should receive the same price signals as similarly sized customers and that non-firm capacity is best compensated through a reservation payment rather than reduced rates, but we are convinced by the parties that to transfer existing non-firm/interruptible rate customers to the BIP reservation payment program now could compromise an important short-term reliability resource for Summer 2005.

BIP operates as a rider to the customer's otherwise applicable tariff. The BIP reservation payment ($7/kW/month) was adopted in D.01-04-006 and was designed to provide the same bill impact to customers as non-firm and interruptible rates do. Therefore, we do not understand how customers could be disadvantaged by switching to BIP from the non-firm or interruptible rates in the long run, but concede that even though the programs are nearly identical from an operational (trigger) standpoint, there could be some short-term confusion on the part of customers associated with the switch to BIP for Summer 2005. Therefore, we conclude it is prudent to exclude non-firm or interruptible load from the default CPP for Summer 2005. Because BIP is a non-firm program designed to serve the same purpose as the non-firm/interruptible rates, for Summer 2005 customers on BIP should also be excluded from participation on a default CCP rate. Thus, the load reduction figures provided by the utilities properly excluded interruptible load.

The DRP provides participants with both a capacity reservation payment and a payment for performance when called. Although the DRP is called the day ahead, it contains penalty provisions for non-performance, unlike other day-ahead demand response programs. Therefore, it operates more like BIP and should be treated the same way for exclusion purposes. Excluding DRP loads from default CPP would further reduce the amount of potential summer peak reductions[33] by 0.1 – 3.2 MW.[34]

Many parties argue that customers over 500 kW should not be subject to a default critical peak pricing tariff because the load profiles of customers over 500 kW are basically flat; thus, although they do impose load at time of peak, their loads do not drive summer peaks like residential and commercial air conditioning loads. In the longer term, we believe that all customers should receive price signals, regardless of their load shape or size, that indicate when power is more expensive to procure. A properly designed CPP rate will most likely result in bill reductions for customers with stable load profiles that do not vary with temperature. Therefore, we would expect that any changes to default rates over time would apply to customers over 500 kW as well as those over 200 kW.[35] However, for Summer 2005, we agree that customers with flat load profiles are generally not well positioned to reduce load on-peak without significant impacts to their core business and therefore customers with 500 kW of

33 Estimates of DRP load were provided in Exhibits 27, 28 and 29. For PG&E, bundled customer DRP load greater than 200 kW is 20 MW, with 10 MW between 200 and 500 kW and 10 MW greater than 500 kW demand. For SCE, bundled customer DRP load greater than 200 kW is 53 MW, with 5 MW of that figure between 200 and 500 kW. For SDG&E, bundled customer DRP load greater than 200 kW is 53 MW, with 6.6 MW of that figure between 200 and 500 kW.

34 3.2 MW uses PG&E upper bound assumptions for customers 200 kW and larger and 0.1 MW uses the more conservative assumptions for customers between 200 and 500 kW.

35 In fact, these very large customers are well positioned to make long-term investments in physical plant and technology that will reduce their load overall, not just on-peak, but they may have more difficulty responding to new rates implemented on such a rapid schedule as anticipated in these applications.

load or greater should be excluded if the Commission implements new default rates for Summer 2005.

Customers served on agricultural schedules also seek exemptions from adoption of any default tariff for Summer 2005. As a preliminary matter, there is a significant difference between the types of customers served on PG&E and SCE agricultural tariffs. PG&E's agricultural tariffs include food processors but SCE's tariffs do not. The other types of customers served on agricultural tariffs are generally water pumpers and farming operations who use electricity to operate their irrigation systems. The most compelling arguments presented about these customers' inability to reduce load on-peak was that farmers rely on the State Water Project and the Central Valley Water Project for water for irrigation and that water is released to them on a schedule established by the Water Project control entities (Department of Water Resources and U.S. Bureau of Reclamation, respectively) that the customers cannot control. (Exhibit 241.) Sometimes customers must use electricity during peak hours in order to perform their irrigation because that is when the water projects release water to them. The problem identified is a legitimate concern and we will alert the proper decisionmakers at the Department of Water Resources and U.S. Bureau of Reclamation about the impact water release decisions have on energy consumption and peak demand issues so that we can better coordinate response to expected high demand days throughout the state.

As we explained with respect to customers over 500 kW, we believe that all customers should receive price signals that indicate when power is more expensive to procure. Thus in the longer term, especially with coordination with the State Water Project and the Central Valley Water Project, we would expect that any changes to default rates would apply to agricultural customers over

200 kW.[36] In the short term, we agree that agricultural customers over 200 kW should be excluded from any revisions to the default tariff for Summer 2005.[37] This exclusion would further reduce the amount of potential summer peak load reduction by 0.6 – 3.4 MW.[38]

Schools, hospitals, and oil pumping customers also seek exemptions as do customers who rely on the utilities for start-up power to restart their electric generators. Oil pumpers and generators both argue that their industries support California's energy infrastructure and reliability needs and should not be subject to revisions to the default tariff for Summer 2005. Schools and hospitals argue they provide vital services that cannot be curtailed. PG&E and SCE already did not include the rate schedules that serve most oil pumping and generation customers in their eligible customer groups. Any other pumping and generation customers that for some reason do not take service on traditional pumping or generation schedules are served under other relevant tariffs for that customer size.

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[36] In fact, in Exhibit 213, Appendix A to AECA's testimony, shows that for SCE's Agricultural and Pumping Rate Group, there is a significant reduction in usage per customer between 10:00 am and 4:00 pm compared to other hours. Thus, over the longer term these customers might actually have some ability to shift load out of a defined critical peak period, with sufficient lead time.

[37] PG&E excluded agricultural load from its figures. SCE estimates coincident peak agricultural load greater than 200 kW to be 132 MW, of which 126 MW is between 200 and 500 kW. (See Exhibit 28.) SDG&E estimates 2005 peak agricultural load greater than 200 kW to be 3.5 MW of which 3.2 MW is between 200 and 500 kW. (See Exhibit 27.)

[38] 3.4 MW uses PG&E's upperbound assumptions for customers 200 kW and larger and 0.6 MW uses the more conservative assumptions for customers between 200 and 500 kW.

Unlike customers over 500 kW and agricultural customers who are served on unique rate schedules, individual electric generators requiring start-up power, individual oil pumping customers, individual schools, and individual hospitals with loads between 200 and 500 kW cannot be easily excluded by simply excluding a tariff schedule from applicability. As we stated for agricultural customers and customers with load greater than 500 kW, in the long term all customers should receive price signals that send signals when power is more expensive to procure. Although we are sympathetic in the short-run to the economic problem that higher prices during a critical peak period might cause to a generator deciding whether to start-up, defining the start-up load to exempt presents practical problems for those served on tariff that were not already excluded. (RT 272.) Therefore, we do not establish an exemption for electric generators requiring start-up power, oil pumping customers, schools, and hospitals with loads between 200 and 500 kW for Summer 2005.

Given the exclusions we have identified for Summer 2005, using the aggressive assumptions of load reduction described in the prior section, the resulting upper bound load reduction potential would be 22.3 MW for PG&E, 32.3 MW for SCE, and 8.0 MW for SDG&E. Using our more conservative assumptions, it would be 4.5 MW for PG&E, 6.4 MW for SCE, and 1.6 MW for SDG&E.

5.3 Is there sufficient time for the targeted customers to be educated about the rates prior to implementation, to understand how to respond for this summer?

Customer representatives responded unanimously that if the Commission issues a decision in April 2005, there is insufficient time to make operational changes or capital investments to assist customers in responding, before the rates become operational in June 2005. Many large customers say that they make energy related capital investments as part of their ongoing business capital planning process and that the investment plans for Summer 2005 are already established. CRA lays it out well in their brief:

> "There is simply not enough time available between now and the summer for program implementation, customer education, and any reasonable expectation that customers can make business adjustments that would be responsive to any CPP program. For those commercial operations that have not already taken all reasonable steps to improve operating efficiency and adjust operations in response to already high electricity rates, some level of investment in new equipment and energy management systems will most likely be required. If mandatory CPP is going to be effective in capturing demand response from buildings that have not yet implemented efficiency and load management practices, then CPP must induce new investment and acknowledge the lead-time required for such new investment. That simply cannot be expected to happen by this summer." (CRA Opening Brief, p. 6.)

In addition, both SDG&E and SCE, because of the structure of their proposed rates, require the customer to make a decision on opting out quickly, for SDG&E by May 15, and for SCE, by June 5. Although the utilities propose to provide educational materials to their customers, most customers between 200 and 500 kW do not have assigned account representatives who can provide individualized education or help them assess the bill impacts from the new rates. Given these facts, we conclude that most customers will not be well positioned to respond to new default rates this summer, even if the bill impacts justified their response.

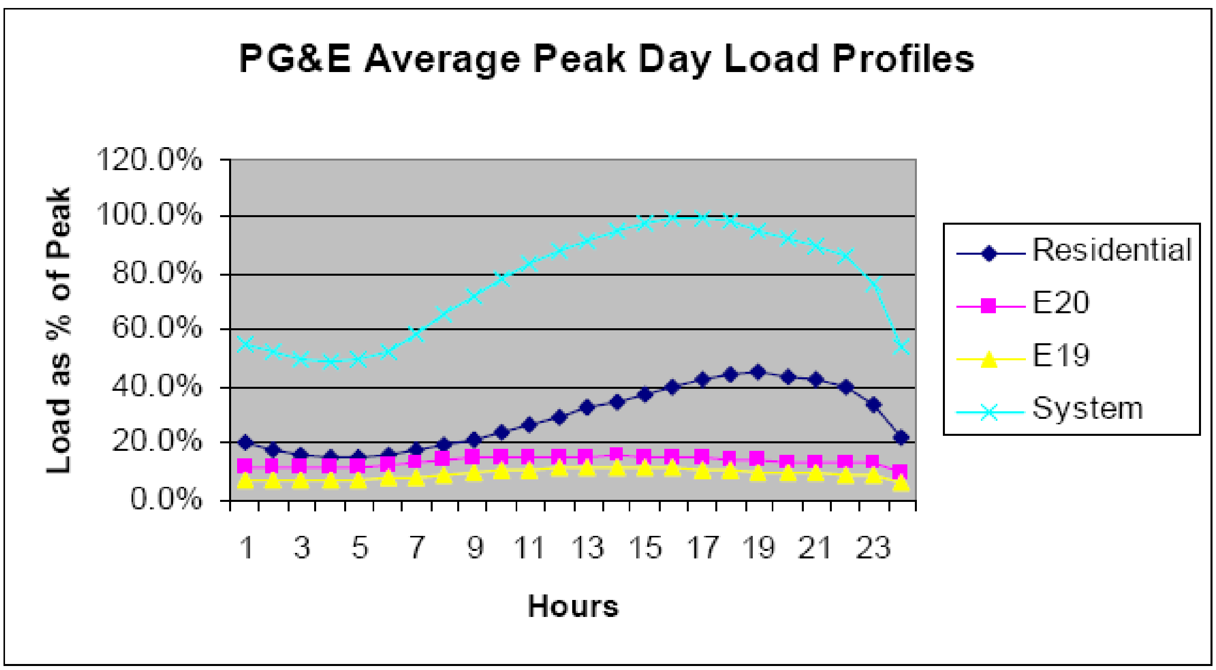
5.4 Given the projected demand response for the targeted customers and issues surrounding short term customer education, should the Commission move forward with implementing a default critical peak pricing tariff for Summer 2005?

As is probably clear by now, there is a resounding groundswell of opposition to implementation of default critical peak pricing tariffs for Summer 2005 by customer representatives, even those who would see lower bills as a result of adoption of these rates. Customers whose bills would increase because of the design of the rates will have little ability to mitigate their increased bills even with significant reduction in their usage. By narrowing the applicability of the rates to non-agricultural customers between 200 and 500 kW in Summer 2005, we significantly reduce the potential demand reduction achievable, even assuming that customers are sufficiently educated to make demand reductions. For these reasons, it appears that implementation of the proposed rates would not accomplish sufficient demand reduction this summer to justify the expected implementation costs of $10.45 million or the disruption to customers. **Therefore, we will not adopt a default critical peak pricing tariff for Summer 2005.**

We also note that these proceedings provided interesting information regarding the contributions to system peak that indicate that the largest customers may not have the most discretionary load to remove from peak. For example, CLECA cited a California Energy Commission (CEC) report[39] that

[39] "Joint CEC/CPUC Proceeding on Advanced Meters, Dynamic Pricing, and Demand Response in California: Connecting Wholesale and Retail Electricity." Denver, CO, April 4, 2003, by Arthur H. Rosenfeld.

identifies that the summer peak is driven by air conditioning load (29% of summer peak load) with another 11% from commercial lighting. Industrial process load represented 5% of summer peak load. EPUC also presented historical load profiles of PG&E's residential, E-19, and E-20 customer classes (reproduced below) that make clear that the residential class places more load on peak than the largest customers. We provide these facts simply for information, without drawing any conclusions about the value that different customers place on their energy usage on peak, which will drive their elasticity of demand and therefore their response to critical peak prices. However, it does indicate that to achieve significant demand response during the critical peak, we will need to place special emphasis on reaching air conditioning load, which drives 29% of the peak load, whether through pricing or other types of programs.



(EPUC Opening Brief, p. 11.)

6. Are the features of the proposed tariffs the best way to design a critical peak pricing tariff for the future?

Although we choose not to implement a new default rate design for Summer 2005, we remain committed to modifying utility rates, through the normal rate design process, to send better signals to all bundled customers to accomplish our policy objectives. We are not convinced that in the long term voluntary rate programs will accomplish our objective of being able to reduce summer peak demand by 5% as set forth in the Energy Action Plan. Therefore, we take this opportunity to lay out the lessons we have learned from this proceeding and provide guidance for the rate design applications currently underway Application (A.) 04-06-024 (PG&E) and A.05-02-019 (SDG&E) and that will be filed shortly by SCE.

We learned in this proceeding that many large customers have facilities in multiple service territories, and often vest responsibility for development of energy management strategies statewide, rather than on a facility-specific basis. Therefore, the general rate design approach, event definition, and event triggers, should be as consistent as possible between service territories although the actual rate of each utility may vary based on its different cost structure. Statewide consistency in design will facilitate customer ability to provide demand response. In particular, we direct the ALJs in A.04-06-024 and A.05-02-019, to suspend the current schedule (if needed) and to require revised rate designs by the subject utilities to accomplish the objectives we set forth below. SCE should also prepare its next rate design application consistent with this approach.

6.1 Investment Signal to Customers

One of the shortfalls of the rates proposed in these applications was that they did not appear to be structured in a way that would motivate customers to reduce demand. For that reason, the ALJ asked all parties to provide their comments on their preference for a rate that includes a fourth higher priced time-of-use period every summer weekday (generally described as between 3:00 and 6:00 p.m.) as compared to a critical peak rate that is triggered the day-ahead for a limited number of days each summer. Most customer groups (although not all) indicated that a fourth fixed time-of-use period would send a stronger investment signal to customers to remove usage from hours targeted than a day-ahead on-call structure. For example, the CLECA witness testified that CLECA member companies would prefer refinement of the TOU pricing periods, potentially by narrowing the on-peak period or by adding a 4th super-peak period, over the implementation of an on-call CPP rate option. She noted that the predictability and regularity of pricing that is set in advance is most likely to permit customers to adapt their operations to new price signals. Others also suggested that instead of adding an additional TOU period, it might make sense to narrow the existing peak period to a shorter number of hours. However, several customers would prefer a rate structure where the pricing differs only when there is an actual emergency or reliability event, more like the structure explored in these applications.

A fourth TOU period allows customers to plan their investments more easily than a day-ahead on-call approach because with a fourth TOU period, the customer knows that if it makes an investment, the rate will be in effect every day and savings will occur every day. Thus the fourth TOU period rate differential leads to a sustained reduction in use from increased investment in efficiency improvements. With a day-ahead call, the customer is less likely to make significant investments in equipment to improve efficiency on a daily basis, because the likelihood of the program being called is unknown.[40] Rather, the customer will evaluate whether or not to reduce load on a given day based on a comparison of the bill impacts of dropping load to the economic impact of a reduction in energy usage on core business. If the bill impacts are insufficient to outweigh the cost of disruption, then reduction in usage is unlikely. This balancing, of course, assumes that the customer is sufficiently educated about the rates in effect and usage patterns to be able to perform this calculation.

Price signals sent by a fourth TOU period result in an overall lowering of peak demand on all days, not just the most critical days, because the prices reflect average costs to provide energy during each time-of-use period, rather than actual market prices. Economic theory says that on non-critical peak days, this outcome is inefficient because it is only during a very narrow set of hours (many fewer than would be encompassed by a fourth TOU period) that there is actual shortage on the electric system and therefore we would be sending improper signals to customers that reducing their load everyday is important. Thus the Commission must decide, as it considers how to motivate customers to achieve demand response, whether its primary objective is a sustained lowering of peak demand or a temporary response to short-term shortage. Which of these objectives it places higher priority on should drive its decision of whether a fourth TOU period (or narrower peak period) or a day-ahead called program better meets the state's needs.

[40] This is not to say that a properly designed CPP would not encourage investment, but rather that a properly design CPP would tend to drive investment in load control technologies and load reduction strategic planning, rather than overall efficiency investments.

We believe that by modifying the approach to adopting revenue requirements for customers with loads greater than 200 kW as described below, we will be better able to accomplish both objectives. We are intrigued by the information provided by CCEA about the significant inertia that customers face when changing their rate schedule, even when a different schedule would provide a lower bill, often as a result of high switching costs. This inertia points to the need for aggressive education efforts to position customers to make the right decisions about whether to remain on a given tariff. SVMG suggests that we place customers on a critical peak pricing tariff as a default, with the ability to convert back to their current TOU tariff.[41] We will adopt this approach, with the TOU rate modified slightly, as described below, with revenue requirements calculated as described below.

In addition, instead of establishing a fourth time-of-use period, we direct the utilities to explore narrowing the current peak period to cover the hours of 2:00 p.m. to 6:00 p.m. The information provided by SCE in Exhibit 16 and the CAISO's Opening Brief convince us that this narrower peak period will generally capture the peak system loads without significant risk of peak shifting. For example, "SCE notes that the average change in load between its peak hour of 3-4 p.m. and non-peak hour of 1-2 p.m. during the ten highest load days in each of several years was approximately 600 to 700 MW. Therefore, for the peak to shift to the 1-2 p.m., for example, the amount of load migration attributable to

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[41] In comments on the proposed decision, CMTA states that adopting the "SVMG proposal" is somehow inappropriate because SVMG did not participate until briefs. On the contrary, the proposal to have the CPP as the default tariff with the ability to return to a standard TOU rate was clearly an issue throughout the proceeding, which is what the SVMG proposal that CMTA takes issue with deals with.

CPP would have to be greater than 600-700 MW." (CAISO Opening Brief, p. 6.) Narrowing the on-peak TOU period will likely increase the peak period price slightly as compared to the current peak period price, but decrease partial- and off-peak rates. This slight change is likely to better signal the price differential between the hours that represent the highest load, and other hours. By narrowing the peak period, the price differential between the peak and partial-peak TOU rates will increase, sending a stronger investment signal than adding a fourth TOU period. At the same time, the TOU rate provides a stable and predictable price for those who prefer certainty over the critical peak pricing rate.[42]

6.2 Establishing Revenue Requirement Upon Which to Design Rates

The key issue for establishing a day ahead critical peak pricing rate for customers 200 kW and above is identifying the correct revenue requirement to collect. In these applications we required the utilities to file rates that were revenue neutral based on existing revenue requirements. We required them to propose a "hedge premium" for customers wishing to remain on a traditional TOU rate. As a result of these requirements, there were structural winners and losers from a bill impact perspective. Because of the designs, customers who did have increased bills would not have seen significant reductions to those bills, even if they made significant reductions in their usage. Because the utilities

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[42] The proposed decision had adopted a narrower time period. Comments on the proposed decision convince us that we need to explore the implications a bit more before directing its adoption.

could not count on reductions in usage from the rates, procurement costs were not reduced.

The revenue requirement used to set current TOU rates includes the costs to serve forecasted load which inherently includes both the expected costs to meet load during normal operating conditions and costs to meet load during higher peak periods. Establishing a revenue requirement that incorporates these higher, more critical period costs is the "hedging" the utility performs as a matter of course in order to ensure that it will recover its revenue requirement under expected load conditions. Therefore, we agree with parties that as long as the revenue requirement used to establish TOU rates includes the costs to meet load during these higher, critical peak periods, no additional hedging premium should be required if a customer chooses not to participate on the critical peak pricing tariff.

In order to send the correct pricing signal to customers under a critical peak pricing rate, the critical peak period costs need to be unbundled from the revenue requirement and recovered from customers only when a critical peak event is called. The Commission should calculate non-critical peak rates based on an adopted revenue requirement for all hours that reflects expected costs in a year with no critical peak events. Separately, the Commission should establish the rate for the critical peak period to reflect the utility's anticipated marginal cost to procure for power for those customers during critical peak periods.[43]

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[43] CMTA and other commenters seem to believe that this approach would somehow allocate <u>all</u> peak procurement costs to the 200 kW and above customers. On the contrary, only that portion of peak procurement costs already allocated to those customer classes would be removed to develop the "no-call" revenue requirement.

In creating new CPP rates in this manner, we shift procurement cost risk to customers who remain on the CPP rate, so we need to establish the base level of revenue requirement that would be recovered in rates assuming no CPP events are called. The no-call revenue requirement would not include certain generation costs, like high spot market prices induced by short term supply-demand imbalances. More stressed market conditions or system supply-demand imbalances would impose larger procurement costs per unit and would be collected in the CPP event price. Clearly identifying the generation related revenue requirements during "orderly" market conditions from incremental generation costs recoverable during a CPP event requires much more precise allocation of generation procurement costs than rate designs have used in the past, but it does not prejudge whether for rate design purposes, the revenue should be recovered via demand or energy charges – that is left to the parties to develop in the rate design phase of these proceedings.

This approach is similar to the approach taken by ORA in that it would recover generation marginal capacity costs in the energy charge during critical peak periods. Our approach differs from ORA's though by separately establishing a revenue requirement for non-critical peak hours assuming no critical peak events occur and setting rates to collect that revenue requirement. By doing so, cost recovery of the revenue requirement is not tied to the number of events that occur as it is under ORA's primary approach. ORA points out in comments on the proposed decision that its alternate rate design approach was not addressed and that it believes its alternate approach addresses many of these concerns.

By removing the costs to meet the higher critical peak loads from revenue requirement allocated to 200 kW and above customers, and charging for those costs only during the critical peak, customers receive a stronger price signal that usage during that period is costly than under a standard TOU rate and will have additional motivation to reduce load during those critical peaks. This approach would allow the utility to fully recover its necessary revenue requirement and avoid procurement costs on peak as customers modify their usage in response to the rates. By calculating rates in this manner, we do not need to establish any particular crediting mechanism for when an event is called, since the revenue requirement being collected from customers on the critical peak pricing rates during non-event hours has already excluded the costs associated with meeting the utility's critical peak needs. Because customers have the option to convert back to standard TOU rate without additional cost, there is no need to exclude any customer group from default tariff applicability.[44]

We do not expect that this approach will require different marginal cost studies or revenue allocation to classes than would normally be performed. Instead, how the rates are designed to recover the revenue allocated to that class, how to extract the critical peak costs to determine the "no-call" revenue requirement, and the proper critical peak rate will be the incremental work required to establish critical peak pricing tariffs.

6.3 Event Triggers

Several different event triggers were proposed for Summer 2005 proposed rates. The primary recommendation was to use an ISO Alert to trigger an event.

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[44] LAUSD again argues in its comments on the proposed decision that we should exempt it from the default CPP. As we do not adopt CPP for Summer 2005, we need not address the exemption issue. Because we provide the option to return to standard TOU rates, without any additional cost, there is no need to exempt any customer types or individual customers as LAUSD, and others, advocate.

SDG&E also proposed a combination of temperature and system load as well as local grid emergencies to trigger a CPP event. However, SDG&E's proposed temperature/load trigger was designed to accomplish 12 calls in the summer in order to limit revenue undercollections from its rate design.

The CAISO defines an "Alert Notice," based on situation following the close of the Day Ahead Market, which closes at 1:00 p.m., as:

> A notice issued by the ISO when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major generation or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Day Ahead Market is short of scheduled Energy and Ancillary services for the ISO Control Area.

In establishing the revenue requirement for the critical peak pricing rate, it is clear that the Commission will need to determine at what level of load costs should be allocated to normal operation (non-CPP hours) vs. critical peak (CPP hours). Based on that assessment, revenue will be allocated to non-CPP hours and CPP hours and rates will be set accordingly. In theory, the load level relied on to perform this allocation should have a relationship to the demand level that the utility must procure reserves for as part of the Commission's resource adequacy requirements. Given the approach we have described for setting revenue requirement to calculate CPP rates, we agree with ORA that the event trigger should bear a relationship to the load levels assumed in rate design and for resource adequacy. We direct each utility in its proposed rate design to designate a specific MW load level for its system that will trigger a CPP event call, consistent with the load level used in its rate design and resource adequacy requirements. For example, this MW level could be set as a specific MW amount or as the difference between the long term and day-ahead forecast load. When the day-ahead load forecast reaches this level, the utility's CPP price will be triggered for the following day. As proposed in the instant applications, notification should be effected by 3:00 p.m. the day ahead.

6.4 Limit on Events

We are convinced by numerous parities that more than four hours is too long for calling a critical event. As described above for our approach to narrowing the TOU period to the 2:00 to 6:00 p.m. time frame, we are convinced that this four hour period will adequately cover the critical peak. We will not specify at this time the number of events that should be called each summer. Instead, in each rate design proceeding, the number of events should be determined based on the forecasts used to allocate revenue to the critical peak. If the forecasts show that there will be five events in the next summer, and revenue is allocated accordingly, then the limit on events should be five. If the forecast shows 12 events, then the event limit should likewise be 12.

6.5 Non-Firm Conversion to BIP

In the short term, we concur that eliminating existing non-firm and interruptible rates is inappropriate. However, given that the BIP reservation payment was designed to provide the same bill impact to customers as the non-firm rates, we see no practical reason from a customer standpoint that the customer would not participate in BIP but would participate on the rate program provided that the customer truly has load it can curtail on short notice. In each utility's rate design proceeding, we will review whether the reservation payment adopted for BIP provides, on average, a consistent bill impact as the non-firm rate discount. In the rate design proceedings, we will ensure that the reservation payment is at a level sufficient to make customers, on average, neutral to the change to a reservation payment program vs. rate discount.[45]

Contrary to what many commenters say, converting to BIP does not eliminate non-firm programs. BIP is a non-firm program designed to provide the same bill effect to customers as the current non-firm tariffs. The fact that less customers have enrolled on BIP than the tariffs appears to be a function of most non-firm load already being served on the tariffs rather than an inherent problem with the BIP design or how responsive customers are who sign up for BIP, given that it has the same triggering and penalty criteria as well as cost basis as non-firm rates. Several commenters assert that there is no basis for converting customers to BIP from the non-firm rate programs, but neglect to mention the fact that for many years now, including as far back as 1992, the Commission has expressed discomfort with the structure of the non-firm rate program, and indicated its intent to move customers to another non-firm program structure. (See for example, D.92-11-049.) Therefore, we make no change to our plan to convert the current non-firm rate programs to the BIP structure over the three year GRC cycles.

For first year CPP is available, we should retain the non-firm rate option rather than immediately migrating customers to either CPP or TOU rate. In second year of the GRC cycle, half of the non-firm rate discount should be removed from the rate and converted into BIP reservation payment. In the third

[45] We would welcome any research performed by Working Group 2 on why the BIP program might not attract customers in the same way that the non-firm rate discounts do, and encourage that research to be submitted as part of the rate design proceedings as the parties consider revisions to the reservation payment level.

year of the GRC cycle, customers would convert either to CPP or TOU rate with the entire non-firm discount provided through the BIP reservation payment.[46]

Participation in BIP while taking service under the critical peak pricing rate should be allowed because under BIP, the customer must commit to a particular firm load reduction level, whereas under the critical peak pricing rate, the customer is not required to reduce its load, although it has the incentive to do so. A BIP event may or may not coincide with a CPP event so there is value in the customer being positioned to respond to either. In fact, if a non-firm customer is on a CPP rate and receives the day-ahead call, they will be even better positioned to respond to a potential emergency the next day, having received a day-ahead notice that supplies were tight. That customer can begin to take steps to adjust its load during the following day in anticipation of the possibility of an emergency call. In any event, should the customer that is currently on a non-firm rate wish to not be exposed to the critical peak pricing rate, it will be able to select the traditional TOU rate with reservation payments for its non-firm load provided through the BIP rider.

6.6 Customer Education Efforts

Once rates are adopted in the rate design proceedings, the utilities will clearly need to provide educational materials to customers to inform them of the upcoming change to the default CPP, the revised TOU peak period and resulting

[46] SCE suggests that the utilities be allowed to present an alternative transition plan for the conversion to BIP. As SCE knows, parties are always free to present alternative approaches to implementing the Commission's directions, provided they also comply with the Commission's decisions. Therefore, the decision does not limit SCE's opportunity to offer an alternative transition plan.

rates, and their option to stay with CPP or switch back to a traditional TOU. In order to ensure that customers have sufficient information to determine whether to remain on the critical peak pricing rate or switch to the traditional TOU rate, once the revised rates are adopted, the utilities shall provide each customer with

load over 200 kW with comparative bills under each rate using that customer's prior summer load data at least two months prior to the start of the summer period.

7. Process for 2006

As described above, we have laid out our policy direction for rate design for establishing a default critical peak pricing rate with an option to remain on a traditional time-of-use rate with a narrowed peak period. Because we have ongoing rate design proceedings underway for PG&E and SDG&E, it is possible that we will be able to accomplish implementation of this policy direction by Summer 2006 for PG&E and SDG&E. SCE will soon file its next rate design proceeding, so we could implement this policy direction for Summer 2007 for SCE.

In the proposed decision, we directed the assigned ALJs in A.04-06-024 and A.05-02-019 to suspend their current schedules and establish new schedules so that the applicants and parties could prepare revenue allocations and rate designs for PG&E and SDG&E consistent with the above principles. Many parties took issue with suspension of the current schedules. After reviewing the comments we do not require the schedules to be suspended. Instead we clarify, as described in Section 6.2, that the CPP rate design should be an additional rate design exercise performed utilizing the marginal cost studies and revenue allocated to 200 kW and above customers, in addition to the need to perform the rate design as it has traditionally occurred. The effort to develop a CPP tariff should be performed consistent with the principles described in this decision but we do not believe this requires us abandoning our normal process with respect to marginal cost studies and revenue allocation.

Many parties point out that it would be useful for the rate design process to occur for all utilities jointly to promote consistency. We agree, and instead of closing this proceeding, will institute a second phase that will begin with an August 1, 2005 filing by PG&E, SCE, and SDG&E. This consolidated second phase will utilize the principles laid out here to develop a consistent methodology for unbundling the critical peak period costs, calculating the no-call revenue requirement, and establishing both the critical peak and non-critical peak rates. On August 1, 2005, PG&E, SCE, and SDG&E should file their proposed rate designs consistent with the principles described herein relying on the most recently adopted revenue allocated to customers 200 kW and above in the case of SCE, or the revenue proposed to be allocated to these customers in the ongoing rate design proceedings for PG&E and SDGE. As described in Section 6.2, because a new revenue allocation is not required to design the CPP rates, we can simply incorporate whatever revenue is allocated in the normal course of the ongoing Phase 2 GRCS to calculate the actual rates. Workshops may assist in developing this methodology and we encourage the parties to hold such meetings in advance of the August 1, 2005 filing. The focus of this consolidated phase will initially be on the methodology by which these principles should be implemented. The August 1, 2005 filings must propose a method that does not rely on credits or other adjustments to non-critical peak rates for critical peak events.

For SCE, its next revenue allocation and rate design should be filed consistent with the principles adopted today and updated based on the consolidated second phase.

Concurrently, we direct Working Group 2, which was formed as part of R.02-06-001, to conduct workshops during the upcoming summer to assist with development of customer education and support plans (building off Summer 2005 programs) for educating customers about critical peak pricing tariffs and development of a measurement and evaluation plan for both tariff impact assessment and customer education and support efforts. Regarding customer education, these efforts should include educating customers about the time-varying cost of power, the high cost of peak load, along with education about the potential technologies and techniques for managing peak load.

Regarding measurement and evaluation, we are particularly interested in additional work by Working Group 2 on how we can utilize the impact assessment information gained from evaluating CPP and demand response programs can be integrated into the Commission's resource planning process. For example, we are interested in seeing protocols developed, based on M&E results, to allow demand response resources to be counted for resource adequacy purposes. We remind the parties, as we laid out in D.03-06-032, that the CEC will supervise all M&E work in coordination with the utilities and the Energy Division that relates to demand response programs and efforts. As has occurred throughout R.02-06-001, the CEC and the Energy Division must play key roles in the monitoring and evaluation process, to ensure that the appropriate data is collected and made available for analysis to support programmatic evaluation. The Working Group 2 facilitator from R.02-06-001 is designated to work with the utilities and parties who wish to be included in this effort, to maintain the required level of coordination, including review of implementation plans, fine tuning of program implementation mechanics within the scope of this decision, and review of compliance filings or tariffs that may be required. In the event of disagreement that cannot be resolved within the Working Group 2 process, the facilitator will bring the matter to the attention of the assigned ALJ to R.02-06-001 who will resolve the matter in consultation with the Assigned Commissioner.

PG&E, SCE, and SDG&E shall provide all data and background information needed to implement the Working Group 2 monitoring and evaluation plan, under appropriate confidentiality protections, as needed, to those involved in the evaluation process. The utilities shall also make this data available to academic researchers, also under suitable confidentiality protection, to facilitate understanding of demand response. The CEC in coordination with the Energy Division shall supervise this work.

8. Modifications to Voluntary Critical Peak Pricing Tariffs

Because we do not adopt a new default critical peak pricing tariff, we make modifications to the existing voluntary CPP tariffs for PG&E (E-CPP), SCE (GS2-TOU-CPP, TOU8-CPP), and SDG&E (EECC-CPP). Under the existing rates, PG&E and SCE participants are charged on-peak energy rates that are approximately five times higher than what they would pay on their otherwise applicable tariff. SDG&E customer have a differential that is 10 times higher. In return, PG&E and SDG&E participants pay lower on-peak and partial-peak rates for the remainder of the summer. SCE customers pay lower on-peak and partial-peak rates for the remainder of the year. Critical peak rates are in effect a maximum of 12 times or 'events' during the summer. Currently, a CPP event is triggered when the utility forecasts high market prices, system constraints or high temperatures. The customer is notified at 5:00 p.m. when the next day is a

CPP event. In 2004, the utilities showed 26 MW enrolled. With the changes that they proposed in their 2005 program plans in R.02-06-001, they expected to enroll an additional 21 MW, bringing the total MW enrolled to 47.

The modifications we consider today were proposed by the utilities in either their 2005 program plan filings in R.02-06-001 (October 15, 2004) or in these applications. As a general matter, we approve most of the changes proposed and in some cases direct that all three utilities implement the change, rather than just the utility that proposed it. We also note that in D.05-03-022 (SCE Phase 2) the Commission approved an optional CPP rate (CPP-GCCD) for SCE customers 500 kW and above. That tariff will remain available without change, but the modifications we discuss below will apply to the optional SCE rate offered to customers 200 kW and above.[47]

8.1 Eligibility Changes

SDG&E proposes that all customers with an interval meter be eligible to participate in the voluntary CPP. SDG&E proposes to promote CPP to small and medium-size business customers as long as they already have an interval meter installed. Given that D.01-05-032 authorized SDG&E to install interval meters for customers 100 kW and above, it is prudent to expand eligibility for the voluntary CPP tariff to all customers with metering technology that allows their participation. Therefore, we approve SDG&E's request to expand the eligible participation in its voluntary CPP program.

[47] Customers 500 kW and above will be able to choose from either rate.

8.2 Notification Changes

PG&E proposes that the notification time be adjusted from 5:00 pm to 3:00 p.m. This modification would allow customers two additional hours to modify their operation for the next day and we approve this change for all three utilities.

In 2004, SCE was authorized to provide customers with a two-day notification period, on a trial basis. SCE states that temperatures fluctuate significantly within a two-day timeframe, thus a CPP event could be called that may not be needed. SCE believes going back to a one-day notification is for the better. We approve this modification.

8.3 Trigger Changes

SDG&E proposes to modify the trigger conditions by lowering the weather forecast to 84 degrees but requiring a specific SDG&E system condition of 3,620 MWs to also occur before an event is triggered. SDG&E also would trigger the program if there is a grid operations emergency. SDG&E would eliminate the market price trigger. SDG&E claims that combining the weather forecast and system conditions into a single trigger is a more accurate trigger for the program than the weather forecast alone. This is the same trigger SDG&E recommended for its proposed default tariff. Several parties commented approvingly on combining system conditions and load to establish a trigger for an event. We agree that this change is reasonable and adopt it for SDG&E. All of SDG&E's proposed changes to its voluntary CPP rates are approved.

PG&E also recommends more ability to adjust the temperature trigger, specifically to be able to move from a monthly to bi-monthly adjustment so that the program is called up to its maximum of 12 times each season. Currently

PG&E adjusts the temperature trigger downward by 2 degrees at the beginning of each month if the program is not being triggered due to cooler weather. Because this program remains voluntary, we believe that it is appropriate to call it as close to the 12 event maximum as possible, in order to provide additional research and exposure to the program. Therefore, we will approve this change for all three utilities, so that they may modify the temperature trigger on a bi-monthly basis if needed. PG&E also proposes a technical adjustment to its algorithm for calculating the average temperature for Zone 2. We adopt the proposed change or PG&E. PG&E's proposed changes to its temperature trigger and algorithm are approved.

SCE proposes that the program be allowed to be triggered for reliability purposes, such as an ISO Alert or Warning. It is not clear what SCE is requesting given that the current program is triggered by ISO special alerts (among other things); therefore we do not make any additional change for SCE's trigger as a result of this proposal.

Under the current tariff, test events are allowed but the number of test events is not specified. PG&E and SCE propose to specify that four test events be allowed for evaluation purposes. We will approve this request for all three utilities and allow the utilities to determine when they want to trigger a test event. For example, PG&E plans to trigger a test event if temperatures are within five degrees of the trigger temperature. SCE would trigger a test event when it appears likely that no event may be called during a month. Test events should count against the event call limits.

8.4 Bill Protection Changes

All three utilities propose to extend the existing bill protection program for new program participants. PG&E also proposes to maintain the bill protection for existing participants beyond the current 14-month term. SCE would shorten the term of the bill protection to 12 months, from 14 months. We will not extend bill protection for existing customers beyond the currently authorized 14-month term. The rationale behind the protection is to allow customers additional exposure to a more dynamic tariff without risk, while they learned whether or not the tariff would work for their operations. After the initial protection period, the customer should decide whether it is able to work with the rate or not, and make a decision whether to remain on the rate or depart. The only advantage we see to PG&E's suggestion that bill protection be allowed indefinitely is to expand its program participation numbers without actually accomplishing any load reduction potential, an outcome we do not approve of. We do agree with SCE that the bill protection period should be shortened to 12 months and continued for new customers. Given the low levels of participation in this program in prior years, we believe that continuing a limited term period of bill protection is warranted to provide that additional level of comfort as customers explore their demand responsive capabilities. PG&E and SCE also recommended that customers be allowed to delay the 12-month bill protection period to allow customers to install technology or make operational changes to help them with their response. We do not see why there would be any advantage to a customer to go on the voluntary rate and pay the tariffed rates without protection and then begin the bill protection period after installing load management technology or making operational changes. In theory, it would be before those changes were made that bill protection was most useful to the customer, not after. Therefore, we do not adopt this change at this time.

8.5 Pricing Changes

SCE proposes to increase the CPP rate differentials so that customers can get higher savings. SCE would increase the partial peak rate under the CPP to $1.29/kWh (from a range of $0.19 - $0.23 per kWh) and increase the peak rate under the CPP to $1.75/kWh (from a range of $0.55 - $0.64 per kWh). Although the increased rate differential might provide additional bill reduction possibilities for customers whose load shapes make them structural winners under the tariff, we are concerned that SCE's customer account representatives are unlikely to direct customers on to this rate if it was apparent that the customer's load shape would require them to reduce load or be hit with the $1.75/kWh rate. SCE is correct that increasing the discounts for the tariff will attract more customers to it, but only if their load shapes are favorable, which will not really assist with demand response capability. Given that we are continuing with a voluntary tariff as this time, we prefer to encourage customers to enroll who are willing to explore seriously their demand reduction opportunities, rather than awarding structural winners with lower bills. Retaining the lower differential under SCE's current rate is appropriate.

8.6 Miscellaneous Changes

SDG&E proposes that the customer's maximum demand on CPP days be disregarded for purposes of determining the customer's monthly demand charge, as long as the customer's maximum demand occurs during non-event hours.[48] SDG&E states that customers can be penalized for responding during a CPP event when they ramp up their operations after the event is over. Certain types of customers could be hit with a much higher demand charge when they respond than would have been assessed if they were not on the rate because demand charges are based on the customer's maximum demand for the month. In particular, this appears to be case for customers with large refrigeration or air conditioning load whose ramp up efforts after an event, even if staggered, create a higher than normal non-coincident peak. SDG&E argues that customers will shy away from CPP participation if there is the potential to incur additional demand charges when they increase their load back to normal capacity. SDG&E's proposal is a logical response to a potential barrier to participation and we approve it for SDG&E. PG&E and SCE may adopt this modification at their option.

9. Incremental Programs to Expand Demand Response for Summer 2005

Because we remain concerned about shortfalls in Summer 2005, we considered several other ways to expand demand response for the coming summer. Many parties commented in their testimony that the Commission should approve proposed modifications to existing demand response programs, rather than implementing a default tariff for Summer 2005. In addition, many parties commented that the December Ruling's focus on customers over 200 kW was misplaced given the load profiles of smaller customers and that more

[48] SDG&E originally proposed that the customer demonstrate a minimum 5% reduction compared to its baseline usage for the maximum demand to be disregarded. SDG&E later modified its request to not require a 5% reduction, and it is this request we consider here.

attention should be given to small customer programs. On January 27, 2005, D.05-01-056 adopted 2005 demand response programs for all three utilities, focused on achieving demand response from all customer segments. Therefore, we believe that we have already been responsive to these calls by parties.

Several parties recommended reopening interruptible/non-firm tariffs to new customers. We decline to do so, in part because in making their proposals to reopen the rates in R.02-06-001, PG&E and SCE did not forecast significant enrollment increases from reopening the rates. Because the BIP programs remain open to customer sign-ups, and we prefer the structure of that program over discounted rates, we find that customers who have the ability to shed load under emergency conditions already have an option to be compensated for making that load available to PG&E and SCE.

9.1 SDG&E Commercial/Industrial 20/20 Program Eligibility

In comments on the proposed decision, SDG&E recommends expanding its Commercial/Industrial 20/20 program authorized in D.05-01-056 for customers between 20 and 200 kW in D.05-01-056 to customers over 200 kW. SDG&E's program requires the customer have an interval meter in place and specifically focuses on the critical peak. Expanding eligibility for the program to customers 200 kW and over is logical and should be adopted.

9.2 SDG&E Day-Of Reliability Tariff

SDG&E, does not have a comparable non-firm rate to PG&E and SCE. For SDG&E we will adopt the Day-Of Reliability Tariff it proposed in this proceeding (CPP-E). This rate provides a high price critical peak price of $3.45/kWh for up to 6 hours a day, for a maximum of 80 hours per year over an entire year. Like the PG&E and SCE non-firm/interruptible rates, SDG&E's proposed rate requires participants to reduce load on 30 minutes' notice in exchange for discounted rates during non-critical peak periods. Given our concerns over sufficient resources to serve Southern California for the upcoming summer, we authorize this rate and the accompanying tariffs set forth in Exhibit 7, Chapter 2, Attachment D.

9.3 Reopen ISO Demand Relief Program

CIPA / COPE propose that the Commission revive the Demand Relief Program Pilot that was operated and funded by the CAISO in 2000 and 2001. CIPA / COPE believe that the program provided significant demand response, was based on a pay-for-performance incentive, and achieved a 90% compliance rate. After evaluating its design, performance and costs in 2000, the ISO re-designed the program for 2001. The program was discontinued by the CAISO in 2002.

According to a 2001 Energy Division report on interruptible programs,[49] the Demand Relief Program was created by the CAISO to attract new load that was not participating in utility interruptible programs and was operated in a similar manner to interruptible programs with customers required to curtail their demand within 30 minutes of being notified for periods lasting two to eight hours. The program had a maximum of 120 hours of interruption. In 2000 the program produced an average of about 40 MWs of interruptible load (out of 65-70 MWs committed) for each summer month. Participants were paid both a monthly capacity payment as well as energy payment. The CAISO made

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[49] "Energy Division's Report on Interruptible Programs and Rotating Outages," February 8, 2001, filed in R.00-10-002.

$7.8 million in total payments in 2000 equating to $124,000 per MW in 2000. For comparison purposes, the utility's average cost per MW for their interruptible programs in 2000 ranged from $73,000 - $118,000 per MW. (Energy Division Report, ibid.) Penalties for non-performance included forfeiture of both energy payments and the monthly capacity payment. The 2001 Energy Division report stated that participants complied 44 – 66% of the time when called to interrupt in 2000, not the 90% compliance rate identified by CIPA/COPE. The program operated just for the summer months and was dispatched AFTER interruptible programs, but before Stage 3 alerts.

The 2001 program allowed for participation through aggregation (or by a single facility) with load equal to or greater than 1 MW by customers not participating in any existing or proposed utility interruptible or curtailable load programs and not part of the CAISO Participating Load Program. Participants would be called on to reduce their loads for 2-8 hours in a day, up to 30 hours a month. In 2001, participants were to be paid a monthly $20,000 per MW reservation payment, and an energy payment of $500 per MWh, with the reservation payment adjusted based on monthly performance. For greater than 50% performance, the participant would be paid the monthly average performance times the reserved demand times $20,000/MW. Between 25-50% the entity would receive a payment that was 2 times the monthly average minus 50% (i.e., with a 26% performance record, the participant would receive 2% of the reservation payment) but below 25% performance, no reservation payment would be made. Other than the adjustments made to the reservation payment just described, no penalties would attach. In 2001, the program was called only once, and produced 162 MWs. The costs for this program were billed to CAISO Scheduling Coordinators based on metered demand and exports.

The structure of the Demand Relief Program was built around utilizing aggregators who were motivated to find load that could accomplish demand reductions. In comparison to other existing interruptible programs, the payments under the Demand Relief Program were quite generous. The current DRP, which is operated by the California Power Authority, was modeled after the Demand Relief Program, but with different pricing terms. It is unclear, given the existing programs in place whether restarting the Demand Relief Program would achieve additional load reductions or whether that load has subscribed to other current programs. In any event, the CAISO has not proposed reopening the program and approval by the Federal Energy Regulatory Commission (FERC) might be required. Therefore we decline to adopt a Demand Relief Program, as proposed by CIPA / COPE, at this time.

9.4 Aggressively Market Existing Programs

CLECA encourages us to direct SCE to use public information and advertising programs to make its air conditioning customers aware of the potential for a generation resources shortfall this summer. CLECA believes a targeted advertising program, which could be amplified in the event we actually experience 1 in 10 weather conditions, could prove to be a very cost-effective method of assuring that air conditioning load is reduced and that a peak resources shortfall is averted. SCE should pursue this approach within the funding authorized for 2005 programs, focusing on all customer types (residential and commercial) that have air conditioning load and aggressively marketing the BIP program.

9.5 Summary of 2005 Programs

Because we are approving modifications to the voluntary CPP programs, we incorporate those changes into the 2005 Program Summary Tables that we adopted in D.05-01-056 and D.05-02-030. Each table lays out the approved program funds for each utility for all 2005 demand response programs, as well as the adopted goals for each program.

Summary of Adopted Utility Demand Response Programs and Goals for 2005 - PG&E

2005 PROGRAMS	COSTS Admin (O&M)	Capital	M&E	Customer Incentives	Total Request	2003-2004 Carryover Allocation	TOTAL NET REQUESTED	Summer 2005 Total Potential MW
Day-Ahead Notification Programs								
Demand Bidding Program (DBP) 2/	$306,000	$100,000	$150,000	$2,835,000	$3,391,000	$1,376,000	$2,015,000	155
CPA Demand Reserves Partnership Program 3/	$500,000	$750,000	$125,000	$0	$1,375,000	$1,375,000	0	245
CPA Managerial Agreement	$500,000	$0	$75,000	$0	$575,000	$575,000	0	N/A
Business Energy Partnership Pilot Program	$1,500,000	$0	$150,000	$850,000	$2,500,000	$0	$2,500,000	10
Critical Peak Pricing Rate	$785,000	$30,000	$475,000	$0	$1.290,000	$0	$1,290,000	25
Adopted Day-Ahead Trigger Programs Subtotal	$3,591,000	$880,000	$975,000	$3,685,000	$9,131,000	$3,475,000	$5,656,000	
Reliability Day-Of Programs								
Base Interruptible Program (BIP)	$100,000	$0	$100,000	$840,000	$1,040,000	$0	$1,040,000	26
Existing Non-Firm rates E-19/E-20 1/								347
Other existing reliability programs			$100,000		$100,000	$50,000	$50,000	13
Develop 2006 A/C Cycling Program	$150,000				$150,000		$150,000	
Adopted Reliability Programs Subtotal	$250,000	$0	$200,000	$840,000	$1,290,000	$50,000	$1,240,000	

1/ This is an existing program. This Decision does not approve the re-opening or expansion of this program. The existing MWs will carry over to 2005.
2/ PG&E's CPP carryover of $1.176 million was re-allocated to DBP.
3/ $149,000 of PG&E's carryover DRP funds remain unallocated and may be reserved for future use for the DRP if needed

PG&E 2005 PROGRAMS	Admin (O&M)	Capital	M&E	Customer Incentives	Total Request	2003-2004 Carryover Allocation	TOTAL NET REQUEST	Summer 2005 Potential MW
Technology Assistance and Incentives								
Technology Assistance and Incentives 4/			100000	7500000	7600000	2976000	$4,624,000	
Adopted Technology Assistance and Incentives Subtotal	$0	$0	$100,000	$7,500,000	$7,600,000	$2,976,000	$4,624,000	
Education, Awareness & Outreach								
Flex Your Power Now! (FYPN!)	$3,130,000	$600,000	$150,000	$0	$3,880,000	$415,000	$3,465,000	
General Education & Outreach	$800,000				$800,000	$0	$800,000	
Emerging Markets and Research 5/	$250,000				$250,000	$115,000	$135,000	
Community Partnership Program	$1,500,000		$0		$1,500,000	$0	$1,500,000	
IDSM	$2,075,000		$50,000		$2,125,000		$2,125,000	
Adopted Education, Awareness & Outreach Subtotal	$7,755,000	$600,000	$200,000	$0	$8,555,000	$530,000	$8,025,000	
Other Programs								
20/20 TOU and Non-TOU - res/commercial	$6,500,000	$0	$100,000	$62,500,000	$69,100,000	$0	$69,100,000	250
M&E Cost Benefit Evaluation Framework 6/			$250,000		$250,000	$250,000	$0	
Adopted Other Programs Subtotal	$6,500,000	$0	$350,000	$62,500,000	$69,350,000	$250,000	$69,100,000	
TOTAL	$18,096,000	$1,480,000	$1,825,000	$74,525,000	$95,926,000	$7,281,000	$88,645,000	1051

4/ PG&E's 2-part RTP carryover of $1.195 million was re-allocated to Technology Assistance and Incentives.
5/ $115,000 of PG&E's carryover M&E funds was re-allocated to Emerging Markets and Research.
6/ $250,000 of PG&E's carryover M&E funds were allocated to M&E Cost Benefit Evaluation Framework.

Summary of Adopted Utility Demand Response Programs and Goals for 2005 - SCE

	COSTS							
SCE 2005 PROGRAMS	**Admin (O&M)**	**Capital**	**M&E**	**Customer Incentives**	**Total Request**	**2003-2004 Carryover Allocation**	**TOTAL NET REQUESTED**	**Estimated Summer 2005 Total Potential MW**
Day-Ahead Notification Programs								
Demand Bidding Program (DBP) 4/	$1,087,656	$409,000	$150,000	$800,000	$2,446,656	$2,446,656	$0	120
CPA Demand Reserves Partnership Program 5/	$191,200	$0	$150,000	$0	$341,200	$341,200	$0	117
Critical Peak Pricing Rate	$25,000	$0	$150,000	$0	$175,000	$0	$175,000	5
Adopted Day-Ahead Trigger Subtotal	$1,303,856	$409,000	$450,000	$800,000	$2,962,856	$2,787,856	$175,000	
Reliability Day-Of Programs								
Base Interruptible Program (BIP)	$105,200	$0	$100,000	$1,560,000	$1,765,200	$0	$1,765,200	79
Existing I-6 & Ag Interruptible Program 1/								539
Existing ACCP - C&I								33
Expanded Air Conditioner Cycling Program (ACCP) - res 2/	$7,650,000	$0	$0	$6,000,000	$7,650,000	$0	$7,650,000	214
Smart Thermostat - small C&I 1/	$879,000	$0	$0	$900,000	$1,779,000			9
Adopted Reliability Programs Subtotal	$8,634,200	$0	$100,000	$8,460,000	$11,194,200	$0	$9,415,200	

1/ This is an existing program. The Decision does not approve the re-opening or expansion of this program. The existing MWs will carry over to 2005.

2/ Incentive costs are paid as a bill credit and were authorized in SCE GRC base revenues and are not part of SCE's requested budget for 2005 programs.

5/ $2,349,519 in 2003-2004 carryover DRP funds remain unallocated and may be reserved for future use for the DRP if needed.

SCE 2005 PROGRAMS	Admin (O&M)	Capital	M&E	Customer Incentives	Total Request	2003-2004 Carryover Allocation	TOTAL NET REQUESTED	Estimated Summer 2005 Total Potential MW
Technology Assistance and Incentives								
Technical Equipment Incentive 4/	$1,138,400	$0	$75,000	$6,000,000	$7,213,400	$3,406,647	$3,806,753	
Education, Awareness & Outreach								
Flex Your Power Now!	$2,690,000	$0	$125,000	$0	$2,815,000	$0	$2,815,000	
Community EE/DR Partnership Demonstration	$801,000	$0	$0	$0	$801,000	$0	$801,000	
Emerging Markets 4/	$1,150,000	$0	$0	$0	$1,150,000	$1,150,000	$0	
Integrated EE/DR Marketing	$452,040	$0	$0	$0	$452,040	$0	$452,040	
Adopted Education, Awareness & Outreach Subtotal	$5,093,040	$0	$125,000	$0	$5,218,040	$1,150,000	$4,068,040	
Other Programs								
20/20 TOU 20 to 200kW	$1,214,748	$0	$50,000	$240,000	$1,504,748	$0	$1,504,748	0
20/20 Summer Rebate -res and small C&I 3/	$4,861,728	$0	$120,000	$70,000,000	$74,981,728	$0	$74,981,728	150
Annual M&E Report 4/	$0	$0	$130,000	$0	$130,000	$130,000	$0	
Adopted Other Programs Subtotal	$6,076,476	$0	$300,000	$70,240,000	$76,616,476	$130,000	$76,486,476	
TOTAL	$22,245,972	$409,000	$1,050,000	$85,500,000	$103,204,972	$7,474,503	$93,951,469	1266

3/ The O&M budget of $4.86 million includes both residential and small commercial 20/20 programs. The MW estimate of 150MW is for both programs as well.

4/ SCE's 2-part RTP carryover of $985,075 was allocated to Demand Bidding Program ($320,368) and Technical Equipment Incentive ($664,707). SCE's CPP carryover of $2,132,624 was allocated to Technical Equipment Incentive. SCE's WG2 Costs carryover of $1,889,316 was allocated to Annual M&E Report ($130,000), Emerging Markets ($1,150,000), and Technical Equipment Incentive ($609,316). SCE's Demand Bidding Program carryover was allocated to Demand Bidding Program.

Summary of Adopted Utility Demand Response Programs and Goals for 2005 - SDG&E

SDG&E 2005 PROGRAMS	COSTS Admin (O&M)	Capital	M&E	Customer Incentives	Total Request	2003-2004 Carryover Allocation	TOTAL NET REQUEST	Summer 2005 Total Potential MW
Day-Ahead Notification Programs								
Demand Bidding Program 1/	$552,000	$600,000	$35,000	$495,000	$1,682,000	$1,007,000	$675,000	28
CPA Demand Reserves Partnership Program (DRP)	$105,000	$0	$10,000	N/A	$115,000	$10,000	$105,000	N/A
C&I 20/20 Program	$483,000	$0	$50,000	$2,141,000	$2,674,000	$393,000	$2,281,000	31
Voluntary Critical Peak Pricing	$374,000	$680,000	$35,000	$0	$1,089,000	$0	$1,089,000	20
Adopted Day-Ahead Trigger Programs Subtotal	$1,514,000	$1,280,000	$130,000	$2,636,000	$5,560,000	$1,410,000	$4,150,000	79
Reliability Day-Of Programs								
Rolling Blackout Reduction Program (RBRP enhanced)	$66,000	$0	$5,000	$248,000	$319,000	$5,000	$314,000	42
Base Interruptible Program (BIP)	$83,000	$0	$5,000	$420,000	$508,000	$5,000	$503,000	6
Existing reliability programs 2/								31
Residential Smart Thermostat (modified)	$431,000	$0	$50,000	$360,000	$841,000	$0	$841,000	2
Adopted Reliability Programs Subtotal	$580,000	$0	$60,000	$1,028,000	$1,668,000	$10,000	$1,658,000	

SDG&E 2005 PROGRAMS	Admin (O&M)	Capital	M&E	Customer Incentives	Total Request	2003-2004 Carryover Allocation	TOTAL NET REQUEST	Summer 2005 Total Potential MW
<u>Technology Assistance and Incentives</u>								
Technology Incentives	$1,194,000	$0	$10,000	$2,250,000	$3,454,000	$5,000	$3,449,000	10
Technical Assistance	$1,059,000	$0	$10,000	$0	$1,069,000	$10,000	$1,059,000	5
Adopted Technology Assistance and Incentives Subtotal	$2,253,000	$0	$20,000	$2,250,000	$4,523,000	$15,000	$4,508,000	
<u>Education, Awareness & Outreach</u>								
Flex Your Power Now! (FYPN!)	$558,000	$0	$50,000	$0	$608,000	$398,000	$210,000	N/A
Customer Education, Awareness & Outreach	$1,990,000	$0	$50,000	$0	$2,040,000	$50,000	$1,990,000	N/A
Emerging Markets	$343,000	$100,000	$10,000	$0	$453,000	$0	$453,000	N/A
Water District Partnership (Engineering Analysis)	$75,000	$0	$0	$0	$75,000	$0	$75,000	N/A
Community Partnerships	$225,000	$0	$50,000	$0	$275,000	$0	$275,000	N/A
Circuit Savers (new)	$76,000	$0	$25,000	$0	$101,000	$0	$101,000	N/A
Adopted Education, Awareness & Outreach Subtotal	$3,267,000	$100,000	$185,000	$0	$3,552,000	$448,000	$3,104,000	
<u>Other Programs</u>								
20/20 Res and Small Commercial 3/	$1,260,000	$0	$100,000	$4,400,000	$5,760,000	$0	$5,760,000	7
Adopted Other Programs Subtotal	$1,260,000	$0	$100,000	$4,400,000	$5,760,000	$0	$5,760,000	
TOTAL	$8,874,000	$1,380,000	$495,000	$10,314,000	$21,063,000	$1,883,000	$19,180,000	182

1/ SDG&E's CPP carryover of $449,000 was re-allocated to DBP, in addition to the existing $558,000.

2/ SDG&E's Other Existing Reliability Programs includes 31MW for AL-TOU-CP.

3/ Adopting SDG&E's proposed "Traditional 20/20" budget, December 1, 2004 filing.

10. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311(d) of the Public Utilities Code and Rule 77.1 of the Rules of Practice and Procedure, but with a shortened comment time as established by the assigned ALJ in the February Ruling, discussed at the PHC where no opposition to the reduction was expressed and confirmed in the Assigned Commissioner's Scoping Ruling of March 11, 2005. Comments were filed on April 11, 2005 and reply comments were filed on April 15, 2005, thereby allowing the Commission to consider the matter and issue a decision sooner than 30 days following issuance of the proposed decision.[50]

Comments were filed by PG&E, SCE, SDG&E, BOMA, Costco, Walmart / JC Penney, ICP, LAUSD, CMTA, BART, EPUC, Farm Bureau, CLECA, ORA, TURN, and Aloha Systems. Reply comments were filed by PG&E, SCE, SDG&E, WPTF, BART, LAUSD, and CCEA. We address the comments throughout the text of the decision and make appropriate revisions in response.

11. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Michelle Cooke is the assigned ALJ in this proceeding.

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[50] The parties' lack of opposition to the reduced comment period is effectively an agreement of all parties that the Commission may act within the § 311(d) 30-day waiting period.

Findings of Fact

1. The reasonably foreseeable 2005 demand reduction from implementing the proposed critical peak pricing rates for all bundled customers 200 kW and larger is 36 MW statewide.

2. Limiting applicability of the proposed critical peak pricing rates to bundled customers 200 – 500 kW reduces the expected load reduction for Summer 2005 to 13.2 MW statewide.

3. The BIP reservation payment ($7/kW/month) was adopted in D.01-04-006 and was designed to provide the same bill impact to customers as the non-firm/interruptible rates.

4. Excluding DRP loads from default CPP would further reduce the amount of potential summer peak reductions by 0.1 – 3.2 MW.

5. Excluding agricultural customers from the tariff would further reduce the amount of potential summer peak load reduction by 0.6 – 3.4 MW.

6. Electric generators requiring start-up power, oil pumping customers, schools, and hospitals with loads between 200 and 500 kW cannot be easily excluded by simply excluding a tariff schedule from applicability.

7. PG&E and SCE proposals do not include the rate schedules that serve most oil pumping and generation customers in their eligible customer groups.

8. Defining the amount of start-up load of generators to exempt from critical peak pricing rates presents practical problems.

9. Many large customers make energy related capital investments as part of their ongoing business capital planning process and investment plans for Summer 2005 are already established.

10. The general rate design approach, event definition, and event triggers, should be as consistent at possible between service territories although the actual rate of each utility may vary based on its different cost structure.

11. Predictability and regularity of pricing that is set in advance is most likely to permit customers to adapt their operations to new price signals.

12. TOU period rate differentials lead to sustained reduction in use from increased investment in efficiency improvements.

13. Price signals sent by TOU rates result in an overall lowering of peak demand on all days, not just the most critical days, because the prices reflect average costs to provide energy during each time-of-use period, rather than actual market prices.

14. The narrower peak period of 2:00 p.m. to 6:00 p.m. will generally capture the peak generation system loads without significant risk of peak shifting.

15. The load level relied on to perform revenue allocation should have a relationship to the demand level for which the utility must procure reserves for as part of the Commission's resource adequacy requirements.

16. A four hour CPP event duration will adequately cover the critical peak generation system demand.

17. PG&E and SCE did not forecast significant enrollment increases from reopening non-firm rates.

18. The BIP program remains open to customer sign-ups.

19. SDG&E's proposed emergency rate requires participants to reduce load on 30 minutes' notice in exchange for discounted rates during non-critical peak periods.

Conclusions of Law

1. The motions to intervene by SVMG and CHA/CSHE are granted.

2. Admission of SVMG's late-served testimony by ALJ Cooke is affirmed.

3. Any other outstanding motions are denied.

4. Transferring existing non-firm/interruptible rate customers to the BIP reservation payment program now could compromise an important short-term reliability resource for Summer 2005.

5. Non-firm/interruptible load should be excluded from the default CPP for Summer 2005.

6. All bundled customers should receive price signals, regardless of their load shape or size, that indicate when power is more expensive to procure.

7. For Summer 2005, we agree that bundled customers with flat load profiles are generally not well positioned to reduce load on-peak without significant impacts to their core business and therefore customers with 500 kW of load or greater should be excluded if the Commission implements new default rates for Summer 2005.

8. The Executive Director should alert the proper decisionmakers at the Department of Water Resources and U.S. Bureau of Reclamation about the impact water release decisions have on energy consumption and peak demand issues so that we can better coordinate response to expected high demand days throughout the state.

9. Agricultural customers over 200 kW should be excluded from any revisions to the default tariff for Summer 2005.

10. We should not establish an exemption for electric generators requiring start-up power, oil pumping customers, schools, and hospitals with loads between 200 and 500 kW for Summer 2005.

11. Given the exclusions we have identified for Summer 2005, using the aggressive assumptions of load reduction described herein, the resulting upper bound load reduction potential would be 22.3 MW for PG&E, 32.3 MW for SCE, and 8.0 MW for SDG&E.

12. Using our more conservative assumptions, it would be 4.5 MW for PG&E, 6.4 MW for SCE, and 1.6 MW for SDG&E.

13. Most customers will not be well positioned to respond to new default rates this summer, even if the bill impacts justified their response.

14. Implementation of the proposed critical peak pricing rates would not accomplish sufficient demand reduction this summer to justify the expected implementation costs of $10.45 million or the disruption to customers.

15. To achieve significant demand response during the critical peak, we will need to place special emphasis on reaching air conditioning load, which drives 29% of the peak load, whether through pricing or other types of programs.

16. The available data regarding contributions to peak load do not allow any conclusions to be drawn about the value different customers place on their peak energy usage or their likely response to critical peak prices.

17. A default critical peak pricing rate for Summer 2005 should not be implemented.

18. Statewide consistency in design will facilitate customer ability to provide demand response.

19. Upon completion of the consolidated second phase of these proceedings, bundled customers should be placed on a critical peak pricing tariff as a default, with the ability to convert without cost to the standard TOU rates adopted for each utility.

20. By narrowing the peak period, the price differential between the peak and partial-peak TOU rates will increase, sending a stronger investment signal than adding a fourth TOU period.

21. As long as the revenue requirement used to establish TOU rates includes the costs to meet load during critical peak periods, no additional hedging premium should be required if a customer chooses not to participate on the critical peak pricing tariff.

22. In order to send the correct pricing signal to customers under a critical peak pricing rate, the critical peak period costs need to be unbundled from the revenue requirement and recovered from customers only when a critical peak event is called.

23. The utilities should establish a revenue requirement for non-critical peak hours assuming no critical peak events and rates to collect that revenue requirement.

24. The utilities should separately identify the costs to meet the critical peak, and charge those costs to usage only during the critical peak.

25. By calculating rates in this manner, we do not need to establish any particular crediting mechanism for when an event is called, since the revenue requirement being collected from customers on the critical peak pricing rates during non-event hours has already excluded the costs associated with meeting the utility's critical peak needs.

26. The event trigger should bear a relationship to the load levels assumed in rate design and for resource adequacy.

27. The MW trigger level could be set as a specific MW amount or as the difference between the long term and day-ahead forecast load.

28. Notification of a CPP event should be effected by 3:00 p.m. the day ahead for all three utilities.

29. SDG&E's request to expand the eligible participation in its voluntary CPP program is reasonable.

30. Continuing a twelve month period for bill protection is warranted to provide that additional level of comfort as customers explore their demand responsive capabilities.

31. PG&E and SCE did not forecast significant enrollment increases from reopening non-firm rates.

32. The BIP program remains open to customer sign-ups.

33. Customers who have the ability to shed load under emergency conditions already have an option to be compensated for making that load available to PG&E and SCE.

34. SDG&E's proposed emergency rate requires participants to reduce load on 30 minutes notice in exchange for discounted rates during non-critical peak periods.

35. SCE should pursue a targeted advertising program targeting air conditioning load.

36. Exhibit 26, 27, 28, 29, and 241 should be received into evidence as of April 11, 2005.

O R D E R

IT IS ORDERED that:

1. The Executive Director should alert the proper decisionmakers at the Department of Water Resources and U.S. Bureau of Reclamation about the impact water release decisions have on energy consumption and peak demand issues so that we can better coordinate response to expected high demand days throughout the state.

2. The utilities shall file new critical peak pricing proposals including testimony, in these dockets on August 1, 2005, consistent with the principles adopted today.

3. In its August 1, 2005 filing, each utility shall designate the specific system conditions that will trigger a CPP event call, consistent with the system conditions used in its rate design and resource adequacy requirements.

4. In each August 1, 2005 filing, the number of events shall be determined based on the forecasts and system conditions used to allocate revenue to the critical peak.

5. In their August 1, 2005 filing, the utilities shall calculate rates for the non-critical peak hours based on an adopted revenue requirement for all hours that reflects costs in a year with no critical peak events and separately establish the rate for the critical peak period to reflect the utility's anticipated marginal cost to procure power during critical peak periods.

6. Southern California Edison Company (SCE) shall prepare its next rate design application consistent with the principles adopted today and update it based on the results of the consolidated second phase.

7. In future rate design applications the utilities shall explore narrowing the current peak period to cover the hours of 2:00 p.m. to 6:00 p.m.

8. Upon completion of these rate design proceeding for each utility, bundled customers shall be placed on a critical peak pricing tariff as a default, with the ability to convert without cost the standard TOU rates adopted for each utility.

9. In each utility's ongoing or future rate design proceedings, the Commission will review whether the reservation payment Base Interruptible Program (BIP) provides a consistent bill impact to the current non-firm rate discount.

10. Over the three year general rate case cycle the rate discount in non-firm rates shall be converted to a reservation payment under BIP.

11. Pacific Gas and Electric Company (PG&E), SCE, and San Diego Gas & Electric Company (SDG&E) shall provide all data and background information needed to implement the Working Group 2 monitoring and evaluation plan, under appropriate confidentiality protections, as needed, to those involved in the evaluation process. The utilities shall also make this data available to the CEC and academic researchers, also under suitable confidentiality protection, to facilitate understanding of demand response. The California Energy Commission in coordination with the Energy Division shall supervise this work.

12. All of SDG&E's proposed changes to its voluntary critical peak price (CPP) rates are approved.

13. PG&E's proposed changes to its temperature trigger and algorithm for its voluntary CPP rates are approved.

14. Four test events for evaluation purposes are approved for all three utilities for voluntary CPP rates.

15. Twelve-month bill protection for new voluntary CPP rate customers should be approved.

16. For SDG&E, the maximum demand of customer on the voluntary CPP rate on CPP days shall be disregarded for purposes of determining the customer's monthly demand charge, as long as the customer's maximum demand occurs during non-event hours. PG&E and SCE may adopt this modification at their option.

17. SDG&E's CPP-E as set forth in Exhibit 7, Chapter 2, Attachment D is approved, effective immediately.

18. SDG&E shall expand the eligibility for its Commercial/Industrial 20/20 program authorized in D.05-01-056 to customers 200 kW and larger.

19. SCE shall pursue a targeted advertising program targeting air conditioning load.

20. Exhibits 26, 27, 28, 29, and 241 are received into evidence as of April 11, 2005.

21. The 2005 Summary Tables in Section 9.4 are adopted.

This order is effective today.

Dated April 21, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
DIAN M. GRUENEICH
Commissioners

APPENDIX A
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